

	OAH 3-2500-20148 MPUC E002/GR-08-1065
--	--

STATE OF MINNESOTA
OFFICE OF ADMINISTRATIVE HEARINGS
FOR THE MINNESOTA PUBLIC UTILITIES COMMISSION

In the Matter of the Application of Northern States Power Company, a Minnesota Corporation, for Authority to Increase Rates for Electric Service in Minnesota	FINDINGS OF FACT, CONCLUSIONS AND RECOMMENDATION
---	---

This matter came on for hearing before Administrative Law Judge Kathleen D. Sheehy on June 2-4 and 9, 2009, in the offices of the Minnesota Public Utilities Commission (Commission), 350 Metro Square Building, 121 Seventh Place East, St. Paul, Minnesota.

Christopher B. Clark, Managing Attorney, and James P. Johnson, Assistant General Counsel, Xcel Energy, 414 Nicollet Mall, Fifth Floor, Minneapolis, MN 55401; and Michael J. Bradley, Esq., and Richard J. Johnson, Esq., Moss & Barnett, 4800 Wells Fargo Center, 90 South Seventh Street, Minneapolis, MN 55402, appeared for Xcel Energy (Xcel).

Valerie Means and Linda S. Jensen, Assistant Attorneys General, 445 Minnesota Street, 1400 Bremer Tower, St. Paul, MN 55101, appeared for the Minnesota Department of Commerce, Office of Energy Security (OES).

Ronald M. Giteck and William Stamets, Assistant Attorneys General, 900 Bremer Tower, 445 Minnesota Street, St. Paul, MN 55101, appeared for the Office of the Attorney General, Residential and Small Business Utilities Division (OAG).

James Strommen, Esq., Kennedy & Graven Chartered, 470 U.S. Bank Plaza, 200 South Sixth Street, Minneapolis, MN 55402, appeared for the Suburban Rate Authority (SRA).

Richard J. Savelkoul, Esq., Felhaber, Larson, Fenlon & Vogt, UBS Plaza, 444 Cedar Street, Suite 2100, St. Paul, MN 55101, appeared for the Minnesota Chamber of Commerce (MCC).

Andrew P. Moratzka, Esq., Mackall, Crounse & Moore, 1400 AT&T Tower, 901 Marquette Avenue, Minneapolis, MN 55402, appeared for the Xcel Large Industrials (XLI).¹

Alan R. Jenkins, Esq., Jenkins at Law, LLC, 2265 Roswell Road, Suite 100, Marietta, GA 30062, appeared for the Commercial Group.²

Lloyd W. Grooms, Esq., Winthrop & Weinstine, Suite 3500, 225 South Sixth Street, Minneapolis, MN 55402, appeared for Verso Paper Corporation.

Janet Gonzalez, Louis Sickmann, Clark Kaml, and Susan Mackenzie participated in the hearing on behalf of the staff of the Commission.

STATEMENT OF THE ISSUES

1. Is the test year revenue increase sought by Xcel reasonable or will it result in unreasonable and excessive earnings?

2. Is the rate design proposed by Xcel, including proposed revisions to customer charges, reasonable?

3. Are the capital structure, cost of capital, and return on equity proposed by Xcel reasonable?

4. What would be the effect and appropriateness of including the Grand Meadow Wind farm in base rates at this time?

Based on the evidence in the hearing record, the Administrative Law Judge makes the following:

FINDINGS OF FACT

1. Xcel Energy Inc. (XEI), a Minnesota corporation, is a public utility holding company. XEI has four utility subsidiaries that serve electric and natural gas customers in ten states, as well as several non-utility subsidiaries. The utility subsidiaries are Northern States Power Co., d/b/a Xcel Energy (NSP-MN), a Minnesota corporation; Northern States Power Co. (NSP-Wisconsin), a Wisconsin corporation; Public Service Company of Colorado; and Southwestern Public Service Co. These utilities serve customers in portions of Colorado, Kansas, Michigan, Minnesota, New Mexico, North Dakota, Oklahoma, South Dakota, Texas, and Wisconsin.

2. On November 3, 2008, Xcel filed a general rate case seeking an annual rate increase of \$156,065,000, or approximately 6.05% of total revenues.

¹ The Xcel Large Industrials are Flint Hills Resources, LP; Gerdau Ameristeel US, Inc.; and Marathon Petroleum Company, LLC.

² The Commercial Group is a consortium of commercial customers, including Best Buy Co, Inc.; Macy's, Inc.; Sam's West, Inc.; Target, Inc.; and Wal-Mart Stores, Inc.

The company used a projected 2009 calendar year as its test year for this proceeding. Xcel also filed a proposed interim rate schedule seeking an interim rate increase of approximately \$155,103,000.

3. On December 23, 2008, the Commission found Xcel's application to be substantially complete as of November 3, 2008. Based on Xcel's agreement, the due date for the final determination in this case was extended to on or about October 23, 2009. On the same date, the Commission issued orders authorizing Xcel to collect \$132,221,000 (or 5.12% annually) in interim rates and initiating a contested case proceeding in the Office of Administrative Hearings.³

4. On February 18, 2009, the Commission supplemented the Notice and Order for Hearing and required the parties to address the effect and appropriateness of including the Grand Meadow Wind Farm in base rates.⁴

5. Pursuant to the First Prehearing Order, the petitions for intervention of the following persons were granted: Xcel Large Industrials, the MCC, the SRA, the Commercial Group, the OAG, the Energy Cents Coalition (ECC), Verso Paper, and the International Brotherhood of Electrical Workers (IBEW), Local Unions 949, 23, and 160.⁵

6. Public hearings were held to receive comments and questions from non-intervening ratepayers. The hearings took place in Minneapolis (April 13, 2009), Winona (April 14, 2008), St. Paul (April 16, 2009), Bloomington (April 20, 2009), Oakdale (April 21, 2009), Mankato (April 23, 2009), St. Cloud (April 28, 2009), and St. Paul (April 29, 2009). The public hearings were not well attended. A total of 19 members of the public participated in the public hearings. Issues of concern in the public hearings were the difficulty faced by residential customers and small businesses in paying increased costs for electricity during hard economic times; the desire to limit executive compensation; the need to expand renewable sources of generation such as wind; the desire by some to increase generation by nuclear facilities, and the desire by others to limit nuclear energy until storage issues have been resolved; the suggestion that smaller users should pay less of the increase than larger users; and the fact that senior citizens who cannot keep up with escalating costs of home ownership, including electricity, will be forced out of their homes. Several persons asked that Xcel provide more detailed factual information to consumers about why the rate increase was necessary.

³ *In the Matter of the Application by Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E-002/GR-08-1065, Order Accepting Filing, Suspending Rates, and Requiring Filing of Waiver (Dec. 23, 2008); Order Setting Interim Rates (Dec. 23, 2008); Notice and Order for Hearing (Dec. 23, 2008).

⁴ *In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E-002/GR-08-1065; *In the Matter of the 2009 Renewable Energy Standard Cost Recovery Rider and 2008 Renewable Energy Standard Tracker Report*, E-02/M-08-1033, Order Supplementing the Notice and Order for Hearing Issued December 23, 2008 (Feb. 18, 2009).

⁵ First Prehearing Order (Jan. 28, 2009).

7. In addition to the comments received during the public hearings, the Administrative Law Judge received a number of written comments (approximately 40) from ratepayers. The written comments similarly focused on the desire to defer any rate increase while people are suffering from job losses during difficult economic times; the need to rely more on renewable resources and decrease reliance on fossil fuels; the desire to have Xcel cut costs, as other companies and customers have done, to survive the current recession; confusion about the charges and riders on Xcel's bills; the need to conserve energy to avoid the cost of new generation facilities and transmission lines; the desire to substantially limit executive compensation; curiosity about why rates should increase when energy prices have fallen; opposition to advertising and marketing expenses; and frustration regarding increases in rates despite the use of conservation measures. A number of senior citizens wrote, objecting to rate increases for those who live on fixed incomes, indicating that they may have to move out of homes that are paid for if they cannot manage to pay their utility bills.⁶

I. PRAIRIE ISLAND LIFE EXTENSION ISSUES

A. Prairie Island Depreciation Expense

8. Xcel's Prairie Island nuclear plant has two reactor units, each rated at 550 MW, located in Welch, Minnesota. The Nuclear Regulatory Commission (NRC) originally licensed the two units in 1973 and 1974, respectively. If not renewed, the current operating licenses will expire in 2013 and 2014. In April 2008, Xcel applied to the NRC for a 20-year license renewal for both units, which would extend the operating lives to 2033 and 2034. The NRC decision is expected to be effective in 2010.⁷

9. In May 2008, Xcel submitted an application to the Commission for an Extended Power Uprate Certificate of Need.⁸ In its application, Xcel proposes to increase reactor power from the current licensed thermal power level of 1650 MWt [megawatt thermal] to 1805 MWt. The corresponding increase to net generator output is estimated at 82 MW per unit.⁹

10. Also in May 2008, Xcel submitted an application to the Commission for a Certificate of Need to expand the dry cask spent-fuel storage to support the life extension requested from the NRC.¹⁰ The Commission's decision is expected in late 2009, and if granted, would become effective at the close of the

⁶ See, e.g., letter from Anabell Hendrickson of Mankato, Minnesota (Apr. 29, 2008).

⁷ Ex. 28 (Bomberger Direct) at 3-4; Ex. 85 (Campbell Direct) at 4.

⁸ *In the Matter of the Application of Northern States Power Company (d/b/a Xcel Energy) for a Certificate of Need for the Prairie Island Nuclear Generating Plant for an Extended Power Uprate*, Docket No. E-002/CN-08-509.

⁹ Ex. 85 (Campbell Direct) at 5.

¹⁰ *In the Matter of the Application of Northern States Power Company (d/b/a Xcel Energy) for a Certificate of Need for the Prairie Island Nuclear Generating Plant for Additional Dry Cask Storage*, Docket E-002/CN-08-510.

legislative session following issuance of the Commission's order, if the legislature takes no action before June 1, 2010.

11. Xcel included in its rate base the nuclear capital expenditures made in 2008 and 2009 for its Prairie Island plant. Investments in the Prairie Island plant amount to approximately \$154.3 million during those two years.¹¹ The issue in this case is whether, and to what extent, the assumptions regarding the remaining life of Prairie Island should be adjusted in anticipation of final decisions on the life extension.

12. Xcel recently went through a similar certificate of need and life extension process with regard to its nuclear plant in Monticello. In its 2005 rate case, which used a 2006 test year, Xcel assumed no extension of life for the Monticello plant beyond 2010. On October 23, 2006, the Commission granted a Certificate of Need for the spent fuel storage needed to operate the plant an additional 20 years beyond 2010.¹² In November 2006, the NRC granted a 20-year extension to the operating license.¹³ When Xcel subsequently petitioned the Commission to extend the depreciable life for Monticello, both OES and Commission staff raised concerns over the magnitude of such a change (a \$26 million annual decrease in depreciation expense) outside of a rate case test year. Specifically, the concern was that declining depreciation expense is not accounted for in rates until the next rate case is brought. This concern was resolved by requiring a rate base adjustment in this rate case equal to the depreciation expense reduction below the 2006 test year level, times the number of years between rate cases.¹⁴ In its most recent generation remaining life filing, OES and Commission staff again expressed concerns about an arguable lack of symmetry between Xcel's depreciation expense and its rates. In October 2008, the Commission ordered Xcel to address in this rate case "(a) the potential imbalance between depreciation and rates potentially caused by a change in the depreciation schedules without an adjustment to costs passed through to ratepayers and (b) include specific alternatives as to how it can better maintain the symmetry between rates and depreciation."¹⁵

¹¹ Ex. 85 (Campbell Direct) at 7.

¹² *In the Matter of the Application of Northern States Power Company, d/b/a Xcel Energy, for a Certificate of Need to Establish an Independent Spent Fuel Storage Installation at the Monticello Generating Plant*, Docket No. E-002/CN-05-123, Order Granting Certificate of Need for Interim Independent Spent Fuel Storage Installation (Oct. 23, 2006).

¹³ Ex. 34 (Robinson Direct) at 6.

¹⁴ *In the Matter of Northern States Power Company's d/b/a Xcel Energy Request for Approval of the Annual Review of Remaining Lives Depreciation for Electric and Gas Production and Gas Storage Facilities for 2007*, Docket E,G-002/D-07-251 (Sep. 21, 2007); Ex. 34 (Robinson Direct) at 14. OES agrees that Xcel has appropriately accounted for the costs and effects of the extension of Monticello's remaining life in this rate case. See Ex. 85 (Campbell Direct) at 14.

¹⁵ *In the Matter of Northern States Power Company d/b/a Xcel Energy's Request for Approval of the Annual Review of the Remaining Lives Depreciation for Electric and Gas Production and Gas Storage Facilities for 2008*, Docket No. E,G-002/D-08-189, Order Approving Service Lives, Salvage Rates, and Resulting Depreciation Rates, With Requirements (Oct. 8, 2008)

13. Some of the \$154.3 million in Prairie Island investments—about \$70 million—were made specifically for the purpose of extending the life of the Prairie Island plant (investments specific to the Prairie Island Uprate and Life Extension dockets identified above). Because these projects will not be “in service” until the license extension of the plant is final, the \$70 million in capital expenditures were included in rate base as Construction Work in Progress (CWIP). Investments treated as CWIP are not depreciated like other capital investments. Instead, these costs are offset by the calculation of an Allowance for Funds Used During Construction (AFUDC), which is recorded as income. After the asset is placed in service, all costs that were deferred during construction are recovered in rates through depreciation expense.¹⁶

14. The remainder of the capital investments for Prairie Island—about \$84.3 million—were or will be made in 2009 for a variety of capital projects, including replacement of coolant pumps, vibration monitoring, compressors, condensate pump motors, bus and switchgear, gearboxes, and purchase of TN-40 spent fuel storage casks.¹⁷

15. Xcel initially proposed to recover all Prairie Island investments in rates through test year depreciation expense of \$64,917,653, which Xcel has calculated assuming a useful life for the Prairie Island units ending in 2013 and 2014, respectively.¹⁸ Thus, Xcel’s depreciation calculation assumes the life of those units will not be extended.

16. In addition to the capital investments already made, Xcel expects to make additional investments in its Prairie Island and Monticello nuclear plants in the amount of \$1.5 billion between 2010 and 2015.¹⁹

17. Xcel anticipates that as its depreciation expense for Prairie Island declines, assuming the plant’s life is extended, its capital investments in both Prairie Island and Monticello plant will correspondingly increase. Xcel proposed what it calls a Nuclear Stability Plan, which is essentially the establishment of a deferred revenue tracker that Xcel believes would stabilize revenues and delay or reduce the need for future rate increases for some number of years. Xcel believes that its plan is responsive to the Commission’s direction to address the potential imbalance between depreciation expense and rates.

18. Xcel’s initial proposal contemplated the collection of depreciation and decommissioning expense in rates, assuming no extension of the life of the Prairie Island plant; when and if the licenses are renewed and the life extension is granted in 2010 or thereafter, Xcel would quantify the value of the reductions in depreciation and decommissioning expense resulting from the life extension compared to the level included in the 2009 test year. Xcel would then record

¹⁶ Ex. 36 (Robinson Rebuttal) at 9-10.

¹⁷ *Id.*

¹⁸ *Id.* at 12.

¹⁹ Ex. 34 (Robinson Direct) at 8.

deferred revenue equal to the annual revenue requirement associated with this reduction, along with a carrying charge to pay ratepayers for the use of their funds. Xcel would offset the deferred balances with capital revenue requirements above the 2009 test year level associated with the extended power uprate projects in Monticello and Prairie Island and the life extension project at Prairie Island.²⁰ Xcel believes this proposal would mitigate the problem of determining the appropriate level of test year depreciation and decommissioning expense and would stabilize prices, rather than allowing prices to swing down then up, potentially outside of a test year. In addition, Xcel acknowledges that this plan provides it with a more timely return on capital invested in large nuclear projects.²¹

19. The OES, OAG, the Commercial Group, and MCC oppose the Nuclear Stability Plan, mainly on the basis that it creates a mismatch between costs and rates. They contend that by failing to use more realistic asset lives to calculate depreciation, rates will be set unreasonably high and depreciation costs will be charged ahead of the benefits that are passed to ratepayers. In addition, they are concerned about administratively tracking deferred costs and revenues outside of a rate case and believe that the reasonableness of new capital costs is more easily reviewed in the context of a rate proceeding.²²

20. Instead, the OES recommends that depreciation expense for all Prairie Island capital investments be calculated assuming that a ten-year life extension will be granted. The OES maintains this approach is reasonable because it significantly reduces the cost and rate effects of assuming no life extension; it is limited to capital costs associated with the Prairie Island plant, as opposed to Xcel's proposal, which includes capital costs for both Prairie Island and Monticello, despite the life extension already granted to Monticello; and by confining the recovery of capital costs to a rate case, it provides Xcel with an incentive to minimize costs.²³

21. In addition, the OES maintains that its recommendation is supported by two recent decisions of the Commission. In the decommissioning docket pertaining to the Monticello plant, the Commission assumed a ten-year life extension for nuclear decommissioning and end-of-life fuel funds accrual in advance of the 20-year life extension that was later granted.²⁴ Significantly, the Commission recently made a similar decision in the decommissioning docket pertaining to Prairie Island, again requiring Xcel to assume a ten-year life

²⁰ Ex. 34 (Robinson Direct) at 8-18; Ex. 28 (Bomberger Direct) at 35-44.

²¹ Ex. 34 (Robinson Direct) at 12-13.

²² Ex. 85 (Campbell Direct) at 18-21; Ex. 66 (Lindell Direct) at 27-39 (Xcel proposal impermissibly would set rates based on future cost of service, rather than actual cost of service); Ex. 64 (Schedin Surrebuttal) at 5.

²³ Ex. 85 (Campbell Direct) at 20-21.

²⁴ See *In the Matter of Northern States Power Company d/b/a Xcel Energy's Petition for Approval of the 2005 Review of Nuclear Plant Decommissioning*, Docket E-002/M-05-1648, Order Setting End-of-Life Dates and Other Guidelines for Nuclear Decommissioning Accrual (Mar. 23, 2006).

extension for the accrual of decommissioning and end-of-life fuel funds. The Commission found that this approach helps ensure that customers who use power from the Prairie Island units pay a fair share of the costs, based on what is known at this time.²⁵

22. Implementing the proposal to extend the life of Prairie Island by ten years results in an increase in rate base of \$9,167,359 and a decrease in depreciation expense of \$30,990,489 for the Minnesota jurisdiction.²⁶ The net overall impact of this adjustment is approximately \$29.6 million.²⁷

23. The OAG supports the assumption of a ten-year life extension for Prairie Island depreciation expense.²⁸ The MCC proposed assuming a 20-year life extension, but it also believes the ten-year proposal made by the OES is reasonable.²⁹

24. In its Rebuttal testimony, Xcel offered an alternative that assumed a three-year life extension (the same assumption it made with regard to decommissioning expense, see below), which would decrease the test year depreciation expense by \$23,464,204.³⁰ This amount is roughly 46% of the amount that is represented by a 20-year life extension and represents the “midpoint” in terms of cost, if not the plant’s potential remaining life. Use of this assumption would decrease the proposed revenue requirement by \$16.6 million.³¹

25. The parties agree that it is likely that the life of the Prairie Island plant will be extended in the near future; Xcel’s Nuclear Stability Plan assumes that the Prairie Island licenses will be extended, as do the proposals by OES and the MCC. Based on the extension already granted for Monticello, and based on the current need for generation resources that limit the consumption of fossil fuels, it is reasonable to assume for purposes of this rate case that the life of the Prairie Island plant will be extended.

26. Although Xcel maintains its alternative three-year assumption is the “mid-point” in terms of cost, depreciation expense is typically calculated based on the remaining life of the plant, not remaining cost.

²⁵ See *In the Matter of Northern States Power Company d/b/a Xcel Energy 2009 Nuclear Plant Decommissioning Accrual*, Docket No. E-002/M-08-1201, Order Approving Decommissioning Plan, As Modified, and Requiring Refund Proposal (Jun. 12, 2009).

²⁶ *Id.*; see also Ex. 85 (Campbell Direct) at 12 & NAC-3.

²⁷ Ex. 85 (Campbell Direct) at 13 & NAC-3.

²⁸ Ex. 68 (Lindell Surrebuttal) at 8-9.

²⁹ Ex. 64 (Schedin Surrebuttal) at 4-5; MCC Initial Brief at 25.

³⁰ Ex. 35 (Robinson Rebuttal) at 4-5.

³¹ *Id.* Xcel calculated depreciation reductions of \$51,290,341, assuming a 20-year life extension; \$42,429,824, assuming a ten-year life extension; and \$23,464,204, assuming a three-year life extension. *Id.*

27. If the plant's life is extended in the next year or two, Xcel's Nuclear Stability Plan will dramatically over-recover depreciation expense for the next several years. Given current economic conditions, it is difficult to justify requiring ratepayers to pay \$29.6 million more than will be required now, so that they can hope to pay less than they otherwise would at some point in the future. The ten-year period recommended by the OES is the mid-point of the expected life extension and is consistent with the Commission's previous decisions regarding decommissioning and end-of-life fuel funds accrual. The ten-year period spreads the \$154.3 million in capital costs for Prairie Island over what should be a more representative remaining life period. In the unlikely event that the licenses are not extended, Xcel's rates could be revised to exclude capital expenses specific to the proposed life extension and to recoup the remaining depreciation expense, assuming the current remaining lives of 2013 and 2014.

28. The Administrative Law Judge accordingly recommends that the Commission reject the Nuclear Stability Plan and instead require Xcel to assume that the useful life of the Prairie Island plant will be extended by ten years and to modify its depreciation expense accordingly.

B. Nuclear Decommissioning and End-of-Life Fuel

29. The issue here is whether accrual of funds for nuclear decommissioning and end-of-life fuel should be treated similarly to depreciation expense, in terms of assuming a life extension for Prairie Island.

30. The purpose of accruing for nuclear decommissioning is to ensure that the amount of money collected annually over the life of the nuclear plant is sufficient at the time of the plant shutdown to cover the cost of decontaminating and removing the facilities at the end of their operating lives. The purpose of accruing for end-of-life fuel is to recover the expense associated with unused nuclear fuel at the time the reactor shuts down. The Commission requires Xcel to submit a nuclear decommissioning review every three years to ensure that these costs are estimated as accurately as possible and that the fund is growing at the rate necessary to cover the eventual costs of decommissioning.

31. As noted above, for purposes of determining its decommissioning accrual, Xcel assumed that the life of the Prairie Island plant would be extended for three years, resulting in test year decommissioning accrual of \$7,504,099 and end-of-life fuel accrual of \$1,458,109.³²

32. For the same reasons noted above with regard to depreciation expense, the OES, OAG, and MCC advocate that in accruing for decommissioning and end-of-life fuel, Xcel should be required to assume that the life of Prairie Island will be extended for ten years.

³² Ex. 85 (Campbell Direct) at 27 & NAC-5; Ex. 15 (Heuer Rebuttal) at 29; Ex. 101 (Campbell Surrebuttal) at 4-5.

33. If the life of Prairie Island is extended by ten years, the decommissioning accrual is reduced by \$7,504,099 and the end-of-life fuel accrual is reduced by \$1,458,109, for a total expense reduction of \$8,962,208.³³ There would also be a corresponding impact on rate base, which would increase the adjustment to \$9,188,873.³⁴

34. The Commission has already indicated that the ten-year period is a reasonable assumption for purposes of these accruals.³⁵ Specifically, the Commission has already determined that Xcel should assume a ten-year life extension in calculating decommissioning and end-of-life fuel.³⁶

35. The Administrative Law Judge accordingly recommends that the Commission treat Prairie Island decommissioning and end-of-life fuel accrual of funds in the same manner as depreciation expense and that the Commission require Xcel to assume the life of the Prairie Island plant will be extended by ten years. If the life extension is denied, the accrual for these purposes can be revised in the next rate case.

II. COST ALLOCATIONS

A. Corporate Cost Allocations

36. NSP is a wholly owned subsidiary of NSP Energy, a registered holding company under the Public Utilities Holding Company Act of 2005 (PUHCA 2005). Under PUHCA 2005, the Federal Energy Regulatory Commission (FERC) is responsible for federal oversight of utility holding companies, with both states and FERC having jurisdiction over cost allocations.

37. NSP Minnesota (NSP-M) is a multi-utility, multi-jurisdictional company that provides electric service to customers in Minnesota, North Dakota and South Dakota and natural gas service to customers in Minnesota and North Dakota, with some non-regulated operations. NSP-M shares goods and services with other parts of NSP Energy, Inc. through its shared services company, NSP Energy Services, Inc. (XES or the Service Company). Services provided by XES include executive management, accounting, financial reporting, finance, treasury, corporate communications, property services, human services, information technology, environmental, legal, regulatory, customer services, engineering, distribution and transmission management and support, and energy supply management and support.³⁷

³³ Ex. 108 (Campbell Summary Statement) at 3; Tr. 2A:25 (Robinson).

³⁴ Tr. 1:84.

³⁵ *In the Matter of Northern States Power Company d/b/a Xcel Energy's Petition for Approval of the 2005 Review of Nuclear Plant Decommissioning*, Docket E-002/M-05-1648 (Mar. 23, 2006).

³⁶ *In the Matter of Northern States Power Company d/b/a Xcel Energy 2009 Nuclear Plant Decommissioning Accrual*, Docket No. E-002/M-08-1201, Order Approving Decommissioning Plan, As Modified, and Requiring Refund Proposal (June 12, 2009).

³⁷ Ex. 19 (Schmidt-Petree Direct) at 4-5; Ex. 85 (Campbell Direct) at 51-54.

38. In 1990 the Commission opened Docket No. G,E-999/CI-90-1008 (the 1008 Docket) and initiated a four-year, industry-wide investigation that resulted in the development of cost allocation principles to guide Minnesota utilities in apportioning costs between their regulated and unregulated operations.³⁸ In the 1008 Docket, the Commission identified the following four basic hierarchical cost allocation principles, extracted from the comprehensive Federal Communications Commission (FCC) cost methodology, as the best means of ensuring proper cost separations between regulated and non-regulated activities:

1. Tariffed rates shall be used to value tariffed services provided to the non-regulated activity.
2. Costs shall be directly assigned to either regulated or non-regulated activities whenever possible.
3. Costs that cannot be directly assigned are common costs which shall be grouped into homogeneous cost categories. Each cost category shall be allocated based on direct analysis of the origin of the costs whenever possible. If direct analysis is not possible, common costs shall be allocated based upon an indirect cost-causative linkage to another cost category or group of cost categories for which direct assignment or allocation is available.
4. When neither direct nor indirect measures of cost causation can be found, the cost category shall be allocated based upon a general allocator computed by using the ratio of all expenses directly assigned or attributed to regulated and non-regulated activities, excluding the cost of fuel, gas, purchased power, and the purchased cost of goods sold.

39. The Commission ordered all gas and electric utilities to be prepared to demonstrate their compliance with these principles in all future rate cases, unless they could demonstrate that (a) their non-regulated activities are insignificant; (b) their alternative cost allocation principles produce results similar to those produced by using the approved allocation principles; or (c) the public interest would be better served by using alternative allocation principles.³⁹

40. The Commission has also recognized the importance of using consistent allocations of a multi-state utility's revenue requirement. It has

³⁸ *In the Matter of an Investigation into the Competitive Impact of Appliance Sales and Service Practices of Minnesota Gas and Electric Utilities*, Docket No. G,E999/CI-90-1008, Order Setting Filing Requirements (Sep. 28, 1994) (1008 Docket or 1008 Order); Order Finding Compliance, Exempting Northwestern Wisconsin, Requiring Preparation, and Closing Docket (Mar. 1, 1995); Order Clarifying Commission Order Dated September 28, 1995 (Mar. 7, 1995).

³⁹ *Id.*, Mar. 1, 1995 Order at 1.

expressly indicated that a company providing service in more than one jurisdiction should use a consistent allocation method to distribute costs among the jurisdictions to avoid over- or under-recovery of the company's revenue requirements.⁴⁰

41. The Xcel Energy Inc. System is heavily focused on regulated utility operations.⁴¹ NSP-M, Public Service Company of Colorado (PSCo), Southwestern Public Service Company (SPS), and NSP-Wisconsin (NSP-W) are regulated entities; Xcel's non-regulated activities are not significant. The relative sizes of NSP-M and its affiliates are as follows:⁴²

Company	Assets	Revenues	Employees
NSP-M	\$10.1B	\$4.3B	4,266
PSCo	\$9.4B	\$3.8B	2,752
SPS	\$2.7B	\$1.6B	1,150
NSP-W	\$1.4B	\$0.7B	602
Xcel Energy Inc. ⁴³	\$8.0B	\$0.6B	11
All Others	\$0.3B	\$0.03B	0
Total	\$31.9B	\$11.03B	8,781

42. As a result, the assignment and allocation of costs to the entities within the Xcel Energy Inc. System is primarily (more than 99%) an assignment and allocation among regulated entities, not an allocation between regulated and unregulated entities, which was the focus of the 1008 Docket.

43. Xcel developed a three-factor General Allocator for costs that cannot be directly or indirectly assigned that is based on assets, revenues, and employee count.⁴⁴ Xcel contends that revenues are appropriately included in the General Allocator because the larger a subsidiary's revenues, the more focus will be placed on that subsidiary's operations due to the subsidiary's relative effect on the consolidated business, income statement, and statement of cash flow.⁴⁵ Xcel believes inclusion of assets is appropriate because the greater the value of a subsidiary's assets, the more focus will be placed on the subsidiary's operations due to the subsidiary's relative effect on the consolidated business and balance

⁴⁰ *In the Matter of the Petition of Northern States Power Company for Authority to Change its Schedule of Rates for Electric Utility Service for Customers Within the State of Minnesota*, Docket No. E002/GR-85-558, Findings of Fact, Conclusions of Law and Order at 23 (June 2, 1986), *aff'd*, *In the Matter of the Petition of Northern States Power Company for Authority to Change its Schedule of Rates*, 416 N.W.2d 719, 728 (Minn. 1987).

⁴¹ Ex. 15 (Heuer Rebuttal) at 33-34.

⁴² *Id.*

⁴³ Xcel Energy Inc. assets include the investment in subsidiaries, and revenues include the dividends from the utility operating companies.

⁴⁴ Ex. 15 (Heuer Rebuttal) at 30.

⁴⁵ Ex.15 (Heuer Rebuttal) at 31.

sheet.⁴⁶ Finally, Xcel uses the relative number of employees because Xcel believes this is a good measure of a subsidiary's importance to the consolidated operations and the time and attention management must pay to the subsidiary's operations.⁴⁷

44. Based upon the recommendation of the OES, the Commission has approved use of this formula by XES to allocate costs to NSP.⁴⁸ Xcel uses the same allocator for its other operating companies (NSP-W, PSCo, and SPS), at the FERC and in all eight jurisdictions in which the regulated companies operate.⁴⁹

45. The Commission accepted Xcel's cost allocations, including its three-factor General Allocator, in the 2004 Gas General Rate Case,⁵⁰ the 2005 Electric General Rate Case,⁵¹ and the 2006 Gas General Rate Case.⁵² Xcel uses the same approach to allocation of costs, including the three-factor General Allocator, for financial and budgeting purposes.⁵³ There have been no changes or updates in the allocation methods since the last rate case.⁵⁴ Since that time, however, Xcel has discontinued or dissolved a number of its non-regulated operations.⁵⁵

46. In this case, Xcel's three-factor allocator results in allocation of 39.74% of unassigned costs to NSP-M.

1. OAG Recommendation

47. The OAG opposes the use of the three-factor General Allocator and recommends a fundamental change in the way in which the General Allocator is calculated, arguing that the Commission should require Xcel to adopt the

⁴⁶ Ex. 15 (Heuer Rebuttal) at 31.

⁴⁷ *Id.*

⁴⁸ *In the Matter of a Request by Northern States Power Company d/b/a Xcel Energy for Approval of an Updated Service Agreement with Xcel Energy Services, Inc.*, Docket No. E,G-002/AI-04-181, Order (Aug. 20, 2004); *In the Matter of a Petition by Northern States Power Company d/b/a Xcel Energy for Approval of an Updated Service Agreement with Xcel Energy Services, Inc.*, Docket No. E,G-002/AI-08-760, Order (Jan. 29, 2009).

⁴⁹ Ex. 15 (Heuer Rebuttal) at 30.

⁵⁰ *In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for Authority to Increase Natural Gas Rates in Minnesota*, Docket No. G002/GR-04-1511.

⁵¹ *In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy, For Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E002/GR-05-1428.

⁵² *In the Matter of the Application of Northern States Power Company, a Minnesota corporation and wholly owned subsidiary of Xcel Energy Inc., for an Increase in Natural Gas Rates in Minnesota*, Docket No. G002/GR-06-1429.

⁵³ Ex. 17 (Heuer Surrebuttal) at 12-13.

⁵⁴ Ex. 19 (Schmidt-Petree Direct) at 11.

⁵⁵ Ex. 15 (Heuer Rebuttal) at (AEH-2), Schedule 11, page 4 of 4.

Commission's general allocator rather than permit continued use of the Xcel's three-factor allocator.⁵⁶

48. The OAG maintains that had Xcel used the Commission's general allocator in 2008, Minnesota ratepayers would have been allocated \$2.3 million less of XES costs.⁵⁷ In the 2009 test year, the OAG maintains that application of the Commission's general allocator would allocate approximately \$3.4 million less of XES costs.⁵⁸ To determine the appropriate test year adjustment, these numbers would have to be allocated to NSP-M and the Minnesota electric retail jurisdiction.⁵⁹

49. The OAG's calculation for 2009 is set forth as follows:⁶⁰

A	B	C
NSP direct and indirect costs:	Total direct and indirect costs	NSP percentage (A/B)%
\$255,297,464	\$671,558,756	38.02%

50. Xcel maintains that this calculation is incorrect for a variety of reasons. First, Xcel points out that the OAG included \$33.3 million of unassigned capital labor costs in the "total direct and indirect costs" used as the denominator, but does not include any of those costs in the numerator. The effect of this calculation is to attribute all of those capital labor costs to other affiliates and none of them to NSP.⁶¹ Xcel argued that this is particularly illogical because NSP has the largest capital investment budget in the Xcel Energy Inc. System.⁶²

51. In addition, Xcel contends this calculation is inconsistent with the Commission's order in the 1008 Docket, which calls for the general allocator to be computed by using the ratio of "all expenses directly assigned or attributed to regulated and nonregulated activities." Xcel argues that the capital costs are not expenses and that, even if they were, they were not directly assigned or attributed to regulated and non-regulated activities, so they should not be included in the calculation. Finally, Xcel disputes the accuracy of the calculation because the data upon which it was based included only XES assignments and allocations of more than \$500,000.⁶³

52. When the capital costs are excluded from the OAG's calculation, the resulting allocator is 40.00%, which is higher than Xcel's three-factor general

⁵⁶ OAG Initial Brief at 30-38.

⁵⁷ Ex. 69.

⁵⁸ Ex. 67 (Lindell Rebuttal) at JJJ-6, p. 3.

⁵⁹ Ex. 67 (Lindell Rebuttal) at 47.

⁶⁰ Ex. 67, Lindell Rebuttal, JJJ-6, p. 3.

⁶¹ Ex. 17 (Heuer Surrebuttal) at 38.

⁶² *Id.* at 37-39.

⁶³ *Id.* at 39.

allocator.⁶⁴ Xcel also estimated total assignments and allocations (not just those of more than \$500,000), and it applied the revised allocator to this number. The result is that \$319,828 more is allocated to NSP-M than by using Xcel's general allocator.⁶⁵

53. Xcel repeated this calculation, using all Operations & Maintenance Expenses (without the \$500,000 limitation) for 2008 and 2009. For 2008, the ratio of NSP-M direct and indirect costs/Total direct and indirect costs is 40.88%; for 2009, the ratio is 40.85%.⁶⁶ Using these allocators, test year expenses would increase by \$89,200 and \$199,377, respectively.

54. The OAG's assertion that Xcel is at fault for providing the inconsistent information upon which its calculations are based is meritless. Xcel provided the information as requested by the OAG. Moreover, this is not simply a dispute about whether capitalized costs as well as expenses are to be included in the calculation, as argued by the OAG. Whether or not capitalized costs are to be considered expenses in formulating an allocator, it is clear under the 1008 Order that the ratio is to include only those costs or expenses "directly and indirectly assigned." The capital costs at issue in this case were not directly or indirectly assigned to any company and should not be included in the calculation.

55. The Administrative Law Judge concludes that Xcel's non-regulated activities are insignificant; its alternative cost allocation principles produce results similar to those produced by using the approved allocation principles; and the public interest would be better served by using Xcel's allocation method. The OAG has not demonstrated that use of the Commission's allocator is required to produce a reasonable allocation of expenses in the test year.

2. OES Recommendation

56. The OES does not generally oppose the Company's three-factor General Allocator, but recommends reductions in 2009 test year expenses of \$1,059,193 in three areas: (i) Legal Services Costs (Work Order 170); (ii) Employee Communications Costs (Work Order 181); and (iii) Xcel Foundation Costs (Work Order 182). The OES recommended revenue requirement would disallow 50% of Legal Non-Corporate Governance costs (\$283,238), 100% of Employee Communications costs (\$450,661) and 100% of administration costs for the Xcel Energy Foundation (\$325,294).⁶⁷

57. Much of the criticism by the OES concerns Xcel's use of number of employees in its General Allocator, rather than labor dollars or full-time employee equivalents (FTEs). An FTE employee number would be based on an assigned percentage of time an employee spends performing work for a given entity. OES

⁶⁴ Ex. 17 (Heuer Surrebuttal) at 39 & (AEH-3), Schedule 14.

⁶⁵ Ex. 17 (Heuer Surrebuttal) at 40 & (AEH-3), Schedule 15.

⁶⁶ Ex. 71.

⁶⁷ Ex. 101 (Campbell Surrebuttal) at 23.

contends that use of employee numbers is not appropriate because this factor does not fully capture labor costs, particularly for smaller non-regulated affiliates that do not have an employee assigned to them on a full time basis. According to OES, Xcel's approach appears to under-allocate costs to non-regulated affiliates, and thereby over-allocate costs to the regulated utility.⁶⁸

58. The OES asserts that either a total labor dollar ratio or perhaps a FTE employee number should be used. It contends that this approach would be far superior to use of physical employee counts for a given entity.⁶⁹

59. Xcel contends that it purposely uses employee numbers (rather than labor dollars) because employee numbers is a more appropriate cost-causative factor than labor dollars, in that most allocated labor costs are related to census, not to salary levels, and the measurement of labor dollars would be subjective.⁷⁰ It contends there are costs associated with attracting, retaining, training, ensuring safety, communicating, and developing benefits that are not dependent on the level of wages, but rather the number of employees. The component for number of employees is intended to provide a unique measure in the general allocator that is a non-financial factor that gives equal weight to each employee, regardless of salary.⁷¹ In addition, even if affiliates have no employees, they are still assigned weighted responsibility for unallocated costs based on their assets and revenues.

60. In response to the OES argument, Xcel substituted 2008 labor dollars for the 2009 budget employee count in calculating the General Allocator. The result was that NSP-M's responsibility increased from 39.74% to 40.53%, and total costs assigned to NSP-M increased by \$972,933.⁷²

61. *Work Order 170.* Xcel used its General Allocator for Work Order 170.⁷³ These costs include the labor and non-labor costs for legal services related to labor and employment law, litigation, rates and regulation, environmental matters, real estate and contracts that are not specific to any operating or non-operating companies but have a general impact on specific companies. The total amount being allocated under this work order is \$1,605,095, and of that \$710,095 was allocated to NSP-M;⁷⁴ \$566,476 was allocated to the Minnesota electric jurisdiction and included in the test year.⁷⁵

⁶⁸ Ex. 85 (Campbell Direct) at 57; Ex. 101 (Campbell Surrebuttal) at 22.

⁶⁹ Ex. 101 at 23 (Campbell Surrebuttal).

⁷⁰ *Id.* at 32.

⁷¹ Ex. 17, Heuer Surrebuttal at 5.

⁷² Ex. 17 (Heuer Surrebuttal) at 7 & (AEH-3), Schedule 7.

⁷³ Ex. 19 (Schmidt-Petree Direct) at (JSSP-1), Schedule 7.

⁷⁴ Ex. 15 (Heuer Rebuttal) at (AEH-2), Schedule 12 & Attachment B.

⁷⁵ Ex. 15 (Heuer Rebuttal) at 36).

62. OES contends the Commission should reduce legal services costs by 50% to \$283,238, as a proxy for the costs over-assigned to NSP's Minnesota electric jurisdiction.⁷⁶

63. The OES questioned the basis for several of the individual expenses reflected in Work Order 170, but it has not asserted that these expenses should not be recovered because they were unreasonable. Its argument against recovery is based on the contention that the use of employee numbers may understate the true labor costs.

64. *Work Order 181.* Xcel allocated costs for Work Order 181 based solely on the number of employees.⁷⁷ Work Order 181 includes the labor and non-labor costs for the development and distribution of communications to employees such as monthly newsletters, etc. The total amount being allocated under this work order is \$1,163,637, with \$565,177 allocated to NSP-M;⁷⁸ of this amount, \$450,661 is allocated to the Minnesota electric jurisdiction and included in the test year.⁷⁹

65. The OES maintains the Commission should order a 100% disallowance of the costs in Work Order 181, as a reasonable proxy for the labor costs and costs under the general allocator that were over-assigned to NSP.⁸⁰

66. Xcel argues that there is no reason to believe that labor dollars have a better cost-causative basis than employee count, particularly in the context of employee communications costs. The use of number of employees as an allocator recognizes that no matter what the employee grade level, the cost to communicate with that employee is the same. It costs no more to send a newsletter to a vice president than it costs to send the newsletter to a lineman. Therefore, Xcel argues the number of employees is the cost-causative factor for employee communications and is the appropriate allocator for the Employee Communications work order.⁸¹

67. *Work Order 182.* Xcel used its General Allocator to allocate costs for Work Order 182.⁸² This work order includes the labor and non-labor costs associated with the management and administration of the Xcel Energy Foundation. The Foundation administers contributions on behalf of Xcel Energy, Inc. and its subsidiaries, makes grants to nonprofit operations, and runs the company's United Way campaign, which matches employee contributions to United Way organizations across the country.⁸³ The total amount being allocated

⁷⁶ Ex. 101 (Campbell Surrebuttal) at 23.

⁷⁷ Ex. 19 (Schmidt-Petree Direct) at (JSSP-1), Schedule 7.

⁷⁸ Ex. 15 (Heuer Rebuttal) at (AEH-2), Schedule 12 & Attachment B.

⁷⁹ Ex. 15 (Heuer Rebuttal) at 35.

⁸⁰ Ex. 101 (Campbell Surrebuttal) at 23.

⁸¹ Ex. 17, Heuer Surrebuttal at 6.

⁸² Ex. 19 (Schmidt-Petree Direct) at (JSSP-1), Schedule 7.

⁸³ Ex. 15 (Heuer Rebuttal) at 39-40.

under this work order is \$1,024,423, and of that \$407,926 was allocated to NSP-M;⁸⁴ \$325,294 was allocated to the Minnesota electric jurisdiction and included in the test year.⁸⁵

68. The OES recommends disallowance of 100% of these costs, arguing that it is not appropriate for ratepayers to pay for the administrative costs related to the Foundation. OES contends these costs should be assigned to Xcel's shareholders, who benefit from the goodwill created by the existence of the Foundation.⁸⁶

69. Xcel argues that it is normal business practice to participate in communities and dedicate resources to administer the contributions associated with that business practice. These costs support Xcel's ability to work with the communities that it serves, and, as such, Xcel argues these costs are prudent, reasonable, and reasonably related to the provision of electric service.

70. In addition, Xcel argues these costs are appropriately charged to administrative and general FERC accounts in accordance with past practice and should be included in the cost of service.⁸⁷ The same functions were performed within XES and were fully recovered in the past, and the creation of the separate legal entity does not justify a change in recovery practice.⁸⁸

71. The Administrative Law Judge concludes that administrative costs associated with the Foundation are a reasonable cost of doing business and that the change in the legal entity responsible for providing the services should not impact Xcel's ability to recover the costs. These costs are necessary to support the corporate giving program; if cost recovery of these expenses were disallowed in rates, it would impact and likely reduce the total amount of charitable contributions from the level that would otherwise be recoverable. The Administrative Law Judge does not believe the statute or Commission policy would mandate that result.

72. The OES has acknowledged that it did not dispute Xcel's allocation method in the past because Xcel's unregulated activities were insignificant, and as such, Xcel was not required to demonstrate compliance with the Commission's cost allocation principles.⁸⁹ The OAG has similarly supported Xcel's allocation method in the past, because its operations in its various jurisdictions were all electric utility operations.⁹⁰ There has been no change in

⁸⁴ Ex. 15 (Heuer Rebuttal) at (AEH-2), Schedule 13 & Attachment B.

⁸⁵ Ex. 15 (Heuer Rebuttal) at 37.

⁸⁶ Ex. 101 (Campbell Surrebuttal) at 23.

⁸⁷ *Id.*; Ex. 15 (Heuer Rebuttal) at 39.

⁸⁸ *Id.*

⁸⁹ See *In the Matter of the Application of Otter Tail Corporation d/b/a Otter Tail Power Company for Authority to Increase Rates for Electric Utility Service in Minnesota*, Docket No. E-017/GR-07-1178, Findings of Fact, Conclusions of Law, and Order at 15-16 (Aug. 1, 2008) (*Otter Tail Power Order*).

⁹⁰ Ex. 70 at 21.

the nature of Xcel's operations since that time, except that more of its non-regulated operations have been discontinued or dissolved.⁹¹

73. The Administrative Law Judge concludes that disallowance of randomly selected costs as a "proxy" for a more precise allocator is an arbitrary way to increase the precision of a method that the OES, in general, finds to be appropriate. It is not a principled method of cost assignment. The ALJ cannot conclude based on the record that the recommended disallowances are either necessary or more reasonable than the costs proposed by Xcel.

74. Moreover, it is difficult to conclude that the allocation of 39.74% of unassigned costs to NSP-M is unreasonable, given that NSP-M has roughly one-third of the company's total assets, one-third of the total revenues, and one-half of the total number of employees. In addition, the General Allocator has been regularly approved in a number of states, including Minnesota. That is not to say that the Commission would be precluded from adjusting the allocator to improve its accuracy. Here, however, use of the General Allocator produces results that benefit ratepayers more than would use of the ratio approved in the 1008 Docket. It also seems clear, based on the relative number of employees, that use of labor dollars would result in higher expenses being allocated to NSP-M. Use of FTEs rather than employee numbers might produce a more precise allocation and would still be consistent with Xcel's argument that employee numbers are the cost-causative factor; this may be an option worth exploring. But Xcel's concerns about tinkering with the allocation method in this docket are justified, since that method is used to determine its revenue requirements in several states.

75. Xcel has indicated it is not opposed to examining possible modifications to its General Allocator, on a forward-looking basis, in a different docket that allows participation by all of its operating companies. The Administrative Law Judge recommends that the Commission accept Xcel's allocation of these costs in this rate case. If the Commission believes that Xcel's General Allocator should be examined to determine whether any systemic enhancements or improvements should be made with regard to the use of employee numbers, the Administrative Law Judge recommends that it be done in a different docket.

B. Allocation of Municipal Revenues and Expenses

76. This issue concerns Xcel's method of separating municipal revenues and expenses from the test year. Xcel has 11 full requirements municipal customers with a total of 24 meters. These customers make up about 2% of Xcel's total sales. Xcel provides capacity and energy to the municipality through use of common transmission and generation facilities, and the municipality acts as an aggregator for customers within its area. Municipal customers are billed market-based rates for their services under a Federal

⁹¹ Ex. 15 (Heuer Rebuttal) at (AEH-2), Schedule 11, page 4 of 4.

Energy Regulatory Commission (FERC) tariff.⁹² Xcel properly removed the revenues generated by wholesale municipal customers from the test year.⁹³

77. Although the Commission does not set rates charged to wholesale customers, it must ensure that costs are properly allocated between jurisdictions in setting rates for retail customers. The OES reviewed cost allocations to municipal customers and concluded that while some cost allocations appeared to be appropriate, it appeared that Xcel under-allocated certain other costs to municipal customers, with the result that retail customers are assigned excessive costs.

78. For expenses relating to distribution, customer accounting, customer service and information, and sales and economic development, Xcel allocated costs based on the average number of customers and counted each municipality as one customer out of 1,388,844 total electric service customers. As a result, municipal customers were assigned 0.0008% of costs in these categories; and if the cost numbers in each category do not round to \$1,000, Xcel counts these costs as zero.⁹⁴ The OES believes it unlikely that residential customers would cause the same level of cost as a municipal customer serving a city.⁹⁵

79. In the absence of better information, OES recommended that \$1,261,834 more in costs be allocated to municipal customers as a proxy for metering and customer services costs. This number was developed in reliance on the 1.25% allocator that results when Xcel's Administrative & General (A&G) wholesale expenses are divided by total company A&G expenses. The OES then multiplied 1.25% times total company customer accounting expense, total company customer service and information expense, and total company sales expense to obtain a total of \$1,728,540, which translates to \$1,261,834 when the Minnesota jurisdictional allocator is applied.⁹⁶

80. Xcel acknowledged that, because there are so few customers in the wholesale municipal jurisdiction, its customer allocator may not have fully reflected customer accounting, customer information, and sales costs related to wholesale municipal customers.⁹⁷ Xcel attempted to review and assign costs more directly and proposed adjustments to increase costs by \$31,000 for billing services, \$20,000 for meter maintenance, and \$112,000 for account management,⁹⁸ for a total assignment of \$163,000 to the wholesale municipal

⁹² Ex. 97 (Campbell Rebuttal) at 14.

⁹³ Ex. 15 (Heuer Rebuttal) at 41-42.

⁹⁴ Ex. 15 (Heuer Rebuttal) at 42.

⁹⁵ *Id.*

⁹⁶ Ex. 97 (Campbell Rebuttal) at 16.

⁹⁷ Ex. 17 (Heuer Surrebuttal) at 19.

⁹⁸ *Id.* at 20-21.

jurisdiction along with a \$55,000 increase in A&G expense. The result of this reassignment is a test year cost reduction of \$194,000.⁹⁹

81. When Xcel groups the costs assigned to the municipal customers, the monthly cost per customer for billing, meter maintenance, and account management is \$1,265.¹⁰⁰ Xcel then compared these costs to those of large commercial and industrial (C&I) customers taking service at the Primary Distribution level, which is the level comparable to the wholesale municipal customers. The Customer Component of the Class Cost of Service Study (CCOSS) includes customer service, billing, and metering costs of providing service to these C&I customers. According to the CCOSS, the Customer Component for C&I customers is \$65.22 per customer per month.¹⁰¹ According to Xcel, this comparison verifies that costs are not being under-allocated to municipal customers.

82. Xcel also maintains that it is not appropriate to use the 1.25% allocator based on A&G expenses as a proxy for municipal customer service and metering costs, because there is no relationship between these costs. The A&G cost is based on plant, operations, and maintenance expenses, and production and transmission are significant elements of both. These costs bear no relationship to the metering and customer service costs at issue. Xcel maintains that, for the most part, wholesale customers do not receive customer accounting services, customer information, and sales cost services. There is only one account manager who provides support to these 11 customers. They are not billed out of the retail billing system, and customer information programs are not directed to them.¹⁰²

83. Two of the municipal customers receive service at the distribution level, not the transmission level, but no distribution costs were assigned to municipal customers. Although the OES is not seeking an adjustment for distribution costs to municipal customers, it believes that this further supports the reasonableness of its recommended adjustment. Xcel disagrees, maintaining that these two customers serve less than 1% (0.6%) of the wholesale/municipal load, and the distribution costs would be insignificant.¹⁰³

84. The Administrative Law Judge concludes that Xcel's proposed assignment of costs to municipal customers is likely low, because its allocation method treats large municipal customers the same as a retail customer. Xcel's *ad hoc* adjustments do not generate a great deal of confidence that all costs have properly been assigned. On the other hand, the OES proposal is likely high and is based on an allocator that bears no demonstrated relationship to municipal metering and customer services costs. In the absence of better data in

⁹⁹ *Id.* at 26-27.

¹⁰⁰ *Id.* at 25.

¹⁰¹ Ex. 17 (Heuer Surrebuttal) at 24.

¹⁰² *Id.* at 23-24.

¹⁰³ Ex. 45 (Heuer Supplemental Hearing Statement) at 2.

the record, the Administrative Law Judge recommends that test year expense be adjusted at the midpoint of these two numbers, which is a decrease of \$727,917.¹⁰⁴ In its next rate case, Xcel should be required to develop a different method of assigning costs, or use a cost study that better captures the expenses incurred by municipal customers so these expenses can be more easily excluded from the test year.

III. RATE BASE ISSUES

A. Grand Meadow Wind Farm

85. Grand Meadow Wind Farm is a 100 MW wind project owned by Xcel Energy and located in Mower County, Minnesota. Grand Meadow is the first wind project owned by Xcel. Previously, Xcel purchased all wind energy under long-term contracts, and those costs were recovered through the Fuel Clause Adjustment (FCA).¹⁰⁵ In 2008, the Commission approved including the costs for Grand Meadow in the Renewable Energy Standard (RES) Rider.¹⁰⁶ In December 2008, Grand Meadow went into commercial operation.¹⁰⁷ In February 2009, the Commission again approved the RES Rider Recovery for 2009, but it directed the parties to address the effect and appropriateness of including the Grand Meadow Wind Farm in base rates.¹⁰⁸

86. Xcel has submitted a firm transmission service request with the Midwest Independent Transmission System Operator (MISO) for delivery of this resource to the Xcel Energy load. Xcel expects that MISO will provide an initial summer peak capacity value of 20% of nameplate capacity; in other words, MISO will assume for purposes of reliability that the wind farm will generate 20% of its nameplate capacity. After three years of additional operating experience is obtained, Xcel expects that MISO will assign the project an annual capacity factor of 39%.¹⁰⁹

87. In response to the Commission's order to address whether Grand Meadow costs should be included in base rates, Xcel proposed that it continue to recover Grand Meadow project costs through the RES Rider until the next rate case, when these costs would be moved into base rates. Xcel maintains that continuing to recover costs through the Rider would allow it to obtain more experience with the variable costs associated with operating and maintaining a wind farm and would also provide Xcel with more certainty regarding recovery of

¹⁰⁴ $[\$1,261,834 - \$194,000 = 1,067,834] / 2 = \$533,917$. $\$194,000 + \$533,917 = \$727,917$.

¹⁰⁵ Ex. 20 (Engelking Supplemental Direct) at 3-4.

¹⁰⁶ Docket E-002/M-070872.

¹⁰⁷ Ex. 37 (Zins Supplemental Direct) at 6.

¹⁰⁸ *In the Matter of the Application of Northern States Power Company d/b/a Xcel Energy for Authority to Increase Rates for Electric Service in Minnesota*, Docket No. E002/GR-08-1065; *In the Matter of the 2009 Renewable Energy Standard Cost Recovery Rider and 2008 Renewable Energy Standard Tracker Report*, E-02/M-08-1033, Order Supplementing the Notice and Order for Hearing Issued December 23, 2008 (Feb. 18, 2009).

¹⁰⁹ Ex. 37 (Zins Supplemental Direct) at 6-7; Tr. 2A:99 (Zins).

operating costs.¹¹⁰ In the alternative, Xcel proposed that if Grand Meadow is included in base rates, the Production Tax Credit (PTC) should not be offset through base rates but should be credited only to any revenue requirement in its annual RES Rider filing.¹¹¹ Xcel maintains this treatment is appropriate because wind production is variable and the amount of the PTC will vary directly with production.

88. Xcel has also said that it is not opposed to including Grand Meadow costs in base rates, as long as there is a true-up mechanism for PTC.¹¹²

89. Xcel initially maintained that inclusion of Grand Meadow in base rates would increase the revenue requirement by \$18.8 million, whereas, if left in the RES Rider, the revenue requirement would be \$17.4 million. This difference is due to Xcel's assumption that, if included in base rates, Xcel would lose \$1.4 million in the Manufacturer's Production Tax Deduction.¹¹³ The calculation assumes that whether the anticipated PTC credits (about \$8 million) are applied to base rates or through the Rider, the net effect would be the same for ratepayers.¹¹⁴

90. The OES and other parties disagreed with Xcel's proposal, maintaining that because Grand Meadow is in service and is being used to serve customers, it should be included now in rate base.¹¹⁵ OES and XLI also dispute that moving the investment to base rates will cost more, maintaining that the effects of the Manufacturer's Production Tax Deduction should be excluded when comparing the cost in base rates versus the cost in the Rider.¹¹⁶ In addition, OES recommends, based on the anticipated assignment of a 20% capacity factor from MISO, that PTCs be allocated to base rates based on the 20% capacity factor, with the remainder flowed through the Rider, and that the actual amount of PTC be trued up in the annual RES Rider filing, based on the amount of wind production in any given year.¹¹⁷

91. The OES also disagreed with Xcel's calculation of the total cost of Grand Meadow, on the basis of a discrepancy between the proposed cost in the Certificate of Need proceeding and the actual cost of \$218.4 million described in Xcel's testimony.¹¹⁸ In its Rebuttal Testimony, Xcel indicated that, based on capital expenditures through 2008, it expected Grand Meadow capital project

¹¹⁰ Ex. 20 (Engelking Supplemental Direct) at 5-9.

¹¹¹ Ex. 37 (Zins Supplemental Direct) at 2.

¹¹² Xcel Initial Brief at 79; Xcel Reply Brief at 51.

¹¹³ Ex. 14 (Heuer Supplemental Direct) at 5-8. Xcel's proposals further assume that unrecovered costs from 2008 will continue to be recovered through the Rider.

¹¹⁴ *Id.* at 8-10.

¹¹⁵ Ex. 80 (Peirce Direct) at 27-28.

¹¹⁶ OES Initial Brief at 48-49.

¹¹⁷ Ex. 80 (Peirce Direct) at 28-29.

¹¹⁸ Ex. 85 (Campbell Direct) at 46.

costs to be reduced \$5,500,400 on a total company basis or \$4,063,906 for the Minnesota electric jurisdiction.¹¹⁹ The OES concurs with this cost reduction.¹²⁰

92. Xcel performed a final calculation comparing base rate recovery versus RES Rider recovery, assuming PTCs are applied to base rates on the basis of the 20% capacity factor and the remainder is flowed through the Rider. The 2010 revenue requirement assuming Grand Meadow is included in base rates (and assuming the use of Xcel's modified revenue deficiency of \$119 million) would be approximately \$15.1 million, whereas the revenue requirement in the RES Rider would be \$14.1 million. Xcel again attributed the difference to the tax expense associated with the Manufacturer's Production Tax Deduction.¹²¹

93. Assuming Xcel has properly accounted for this deduction, the difference in cost recovery between base rates and the RES Rider decreases significantly over the next five years. In its Reply Brief, Xcel appears to acknowledge that the tax deduction should not be considered in determining whether to keep Grand Meadow costs in the Rider or to move them to base rates.¹²²

94. The XLI agrees with the OES that the costs of Grand Meadow should be moved into base rates. The XLI would agree to continue recovery through the Rider only if wind costs are classified on a system resource basis in the Class Cost of Service Study (CCOSS). It contends that the PTC could be recovered either in base rates or through the Rider, but believes it is too administratively difficult to credit a portion to base rates with a true-up through the Rider. If recovered in base rates, the XLI maintains that 39% of the PTC should be allocated to base rates, based on MISO's expected annual capacity rating.¹²³

95. The MCC asserts that Grand Meadow costs (and all wind turbine costs) be recovered through the RES Rider using a "levelized" approach, in which a flat rate is prescribed over the useful life of the resource. There would be an annual true-up of the PTCs for the ten-year period in which those credits are available. The MCC also argues that the \$4.6 million in unrecovered costs from 2008, which Xcel has included in its 2009 Res Rider filing, be similarly amortized over a ten-year period. In the alternative, MCC maintains the actual costs should be recovered exclusively through the respective riders for the life of the projects. The MCC's recommendation would exclude the initial high costs of

¹¹⁹ Ex. 15 (Heuer Rebuttal) at 8.

¹²⁰ Ex. 101 (Campbell Surrebuttal) at 19; Tr. 3:164 (Campbell); Ex. 108 (Campbell Summary Statement) at 1.

¹²¹ Ex. 117.

¹²² Xcel Reply Brief at 52.

¹²³ XLI Initial Brief at 22-23.

the project from rate base until those costs are reduced through depreciation and tax deductions.¹²⁴

96. Riders are legislatively authorized mechanisms allowing cost recovery outside of a general rate case. By providing faster cost recovery, riders remove a significant disincentive to undertaking projects that the legislature and the Commission have determined to be in the public interest. The normal regulatory process is to move costs from riders into base rates at the first opportunity so that new projects replace old projects in base rates. The Administrative Law Judge accordingly recommends that the costs of Grand Meadow be moved into base rates for 2010 because the project is in service.¹²⁵

97. In addition, some portion of the PTC should be allocated to base rates so that ratepayers receive some benefit of the credit there; the proposal by the OES to allocate the anticipated credit based on a capacity factor of 20% is a reasonable estimate.¹²⁶ The remaining amount of the PTC would be flowed through the Rider and trued up annually. If Xcel does not object to the administrative difficulty of truing up the remaining credit through the Rider, it is hard to see why the XLI should object to such a process.

98. The adjustments to accomplish this change are an increase of approximately \$109 million to rate base and a decrease of approximately \$1.7 million in operating income.¹²⁷

99. The Administrative Law Judge also recommends that the proposal by the MCC to recover such costs through the Rider for the life of the project and to spread the recovery of unrecovered 2008 costs over a ten-year period should be rejected. This approach would substantially increase the total cost to ratepayers due to the carrying charge that would be applied. The purpose of recovery through a rider is to allow the utility to begin recovering its costs in a timely manner, not to provide a permanent substitute for rate base treatment of investments in renewable energy.

100. The OES recommended that Xcel's actual revenues already collected through the RES Rider be used as a credit against the costs included in rates for the Grand Meadow wind project, or alternatively, recommended that Xcel use the actual revenues to adjust the amount recovered through a RES Rider adjustment.¹²⁸ Xcel accepted the use of the alternative proposal to include a true-up in the RES Rider.¹²⁹ Xcel will include a true-up of the 2009 RES Rider

¹²⁴ Ex. 61 (Schedin Direct) at 25-26; Ex. 63 (Schedin Rebuttal) at 5-6; Ex. 64 (Schedin Surrebuttal) at 21-22.

¹²⁵ These numbers have not been included in any rate base calculation made by Xcel or OES for purposes of determining the final revenue deficiency in this case.

¹²⁶ The fixed amount used to reflect this estimate of the credit is \$2,679,432. See Ex. 15 (Heuer Rebuttal) at 10.

¹²⁷ Ex. 117 at Schedule 4, page 1.

¹²⁸ Ex. 101 (Campbell Surrebuttal) at 20.

¹²⁹ Ex. 45 (Heuer Supplemental) at 2.

revenue to actual revenue requirements by including the true-up in the development of the 2010 RES Rider rate.¹³⁰ Thus, the true-up will return the difference to customers during 2010.¹³¹ The OES and Xcel consider this issue resolved.

101. To address concerns about the double recovery of costs if Grand Meadow is rolled into base rates, the OES proposed that Xcel provide a compliance filing demonstrating that no double recovery of costs had occurred during the interim rate period.¹³² Xcel agreed to provide a compliance filing to demonstrate that no double recovery of costs had occurred during the interim rate period.¹³³

B. Cash Working Capital

102. The OES reviewed Xcel's calculation of cash working capital and found its lead/lag analysis to be reasonable.¹³⁴ The OES and Xcel agree that cash working capital will need to be recalculated using these factors after the final adjustments to rate base, revenues, expenses, and capital structure are made.¹³⁵

IV. OPERATING INCOME ISSUES

A. Nuclear Fuel Outage Costs

103. Each of Xcel's three nuclear-powered reactors requires re-fueling in cycles ranging from 18 to 24 months. In some years only one reactor is re-fueled; in other years, two reactors are re-fueled, with a potential that three refueling outages could occur in some years. Because the reactors are out of service during refueling, Xcel takes this opportunity to perform necessary repairs and maintenance that cannot be performed when the reactors are operating. Individual fuel outage costs can range from \$15 million (for an outage with minimum scope) to up to \$40 million, depending on the level and complexity of required periodic inspections or maintenance activities. These costs are trending upward over the period 1999-2009. In 2009, refueling outage costs were higher because of the increased outage length at Monticello to install modifications necessary to support the extended power uprate.¹³⁶

104. Under the Federal Energy Regulatory Commission (FERC) Uniform System of Accounts (USOA), the cost of fuel installed in reactors is recorded to an asset account and amortized to allow a reasonable matching of the costs with the energy produced. Historically, Xcel used the direct expense accounting

¹³⁰ *Id.*

¹³¹ *Id.*

¹³² Ex. 80 (Peirce Direct) at 29.

¹³³ Ex. 15 (Heuer Rebuttal) at 12-13.

¹³⁴ Ex. 13 (Heuer Direct) at 56-57; Ex. 103 (Lusti Direct) at 7-8.

¹³⁵ Ex. 103 (Lusti Direct) at 8; Ex. 15 (Heuer Rebuttal) at 14.

¹³⁶ Ex. 28 (Bomberger Direct) at 27-29.

method, where costs of re-fueling were expensed as they were incurred, leading to large swings in expenses from year to year, depending on the number of outages that occurred.¹³⁷

105. In November 2007, Xcel requested permission to use the deferral-and-amortization accounting method for financial reporting purposes, under which Xcel would record the re-fueling costs incurred (other than fuel) as an asset at the time of the re-fueling operation and amortize the cost to expense during the period between re-fueling outages. The Commission approved the proposed accounting change in an order that further provides:

The deferral-and-amortization method will spread the costs of nuclear re-fueling over the full re-fueling cycle instead of incurring those costs in one month. This method will likely better match the costs of service to the period/benefits of service and provide useful cost information for regulatory purposes.

Moreover, once the method is fully implemented, costs presented in rate proceedings will reflect the costs incurred to provide the benefit of nuclear generation on a more levelized basis. This method will also likely benefit Xcel through smoothing the impact to the company's financial statements. Thus, the deferral-and-amortization method will potentially provide a better, more representative cost level than the current method, as it is better positioned to produce a representative cost level for reflection in customer rates compared to the direct-expense method.

Further, in future rate proceedings, proposed test year re-fueling costs will be subject to review for reasonableness. Xcel is reminded that the burden of proof regarding the reasonableness of the costs included for recovery remains with Xcel. The Company shall maintain adequate records of actual costs, amounts deferred, and amortization of refueling costs and provide that information in future rate case filings as support for test-year re-fueling costs.

The Commission cautions, however, that approval of the proposed accounting methodology in this proceeding does not mean that the commission is not free to employ its normal rate setting procedures when the Company files a rate case. Commission approval of the deferral-and-amortization methodology should not be read to suggest that the Commission has pre-approved some form of exact cost recovery in future rate cases.

¹³⁷ *In the Matter of a Petition by Northern States Power Company, a Minnesota Corporation, for Accounting Treatment for Nuclear Refueling Outage Costs*, Docket No. E-002/M-07-1489, Order Approving Change in Accounting Methodology With Conditions (Sep. 16, 2008).

Instead, the Company will, as always, bear the burden of proof that the proposed cost for re-fueling is reasonable—with those costs clearly subject to a reasonableness and prudence review in a rate case—where the Commission will make its determination of a reasonable cost using standard rate making principles. For the foregoing reasons, the Commission finds that permitting the use of the deferral-and-amortization methodology for nuclear refueling costs is appropriate, and will so order.¹³⁸

106. In 2009, Xcel's actual nuclear outage costs are \$51.7 million, or \$37,660,773 for the Minnesota jurisdiction. Using the deferral-and-accounting methodology, Xcel proposed a test year revenue requirement for nuclear outage costs in this rate case of \$30,692,218.¹³⁹ This number represents an income statement revenue requirement of \$29,487,219 and a rate base revenue requirement of \$1,204,998.¹⁴⁰

107. The OES does not object to Xcel's proposed test year expense or to use of the deferred accounting method to develop the expense in this case. Although the OES believes the methodology issue should be examined on an ongoing basis, the OES believes that the proposed test year expense is reasonable and that Xcel has properly implemented the Commission's ordered adjustments to reflect the accounting transition. The OES pointed out that it could have used an historical average or other method to estimate the outage costs, but did not do so because these costs are trending upward, and any test-year expense developed using an average of historical costs should include an adjustment for the upward trend.¹⁴¹

108. The OAG recommends that the Commission not permit Xcel to use the deferred accounting method to develop a test year expense. It maintains that these expenses do not qualify for deferred accounting treatment under previous Commission decisions because they are not significant or extraordinary and that use of this method will result in a "regulatory asset" upon which Xcel would inappropriately earn a return on deferred balances. The OAG also contends that this methodology will result in less oversight by the Commission because there is a presumption that by deferring these costs, they will be recovered.¹⁴²

109. The OAG developed a "normalized" test year expense of \$31,172,000 by averaging the actual expenses for 2005 through 2008 and the projected costs budgeted for 2009.¹⁴³ This time frame includes a year (2007) in which only one refueling outage occurred.¹⁴⁴ The OAG's proposed expense for

¹³⁸ *Id.* at 6-7 (footnote omitted).

¹³⁹ Ex. 85 (Campbell Direct) at 21-24.

¹⁴⁰ Ex. 66 (Lindell Direct) at 23 & JJJL-4.

¹⁴¹ Ex. 85 (Campbell Direct) at 25; Ex. 28 (Bomberger Direct) at 27.

¹⁴² Ex. 66 (Lindell Direct) at 15-27.

¹⁴³ Ex. 66 (Lindell Direct) at 19.

¹⁴⁴ Ex. 28 (Bomberger Direct) at 27.

the test year is higher than Xcel's claimed expense using the deferral and amortization methodology, but it would not result in any rate base impact.

110. The process of developing a properly normalized expense involves a number of subjective determinations, such as how to select the appropriate historical period; how to weight the value of different years, if appropriate; how to treat years with different numbers of outages; how to develop an appropriate inflation adjustment; and, as the OES pointed out, how to recognize an upward trend in the expense. The point is to develop a representative test year number, not to simply perform a mathematical average. The OAG has not demonstrated that its proposed expense reflects a representative number for the test year.

111. These are significant expenses. For financial accounting purposes, Xcel is willing to defer full recovery of those expenses to obtain the benefit of more predictable and stable financial reporting. Use of this method to develop the test year expense in the rate case has had the effect of benefiting ratepayers as well, by substantially reducing the test year expense as compared to actual expense. The relatively small impact on rate base is part and parcel of this methodology and cannot reasonably be eliminated. Moreover, from a ratepayer perspective, the rate base impact is justified by the overall reduction in expense. And use of the deferral-and-amortization method in this case eliminates the subjectivity involved in creating a properly "normalized" expense. If, in the future, use of the deferral-and-amortization method has a different result for ratepayers, the Commission is free to re-examine the claimed expense to ensure that it is reasonable. The Commission has made it clear that, regardless of the method used to develop this expense, the proposed numbers will be subject to rigorous scrutiny, and there is no presumption that deferred costs will be recovered in any rate case. For all these reasons, the Administrative Law Judge recommends that Xcel's proposed nuclear fuel outage cost be used in determining test year expense.

112. To help interested parties understand the impact of nuclear plant outage costs, the OES requested that Xcel provide the analysis shown in OES Information Request 140 as part of the initial filing in future rate cases.¹⁴⁵ Xcel agreed to provide the analysis shown in OES Information Request 140 as part of future rate case filings.¹⁴⁶

B. Rate Case Expense

113. Xcel requests recovery of current rate case expenses of \$1,593,811, to be amortized over four years. The OES found this level of expense and the amortization period reasonable.¹⁴⁷

¹⁴⁵ Ex. 85 (Campbell Direct) at 25.

¹⁴⁶ Ex. 15 (Heuer Rebuttal) at 40-41.

¹⁴⁷ Ex. 103 (Lusti Direct) at 12-14.

114. The OAG proposes two changes. First, it proposes reducing the amount of the rate case expense proportionally, by the same percentage that the final Commission-approved revenue requirement is to the initially requested increase in rates. For example, if the Commission were to approve a revenue requirement of \$78 million, or 50% of Xcel's initially requested increase of \$156 million, then Xcel would be permitted to recover 50% of its rate case expenses. It is not clear exactly how this would be implemented, as the revenue requirement assumes that all appropriate expenses have been included in the calculation. Second, while the OAG supports a four-year period for recovering the rate case expenses, the OAG proposes treating this as a normal annual expense rather than as a one-time expense amortized between rate cases.¹⁴⁸

115. The OAG describes its proposal as an expense control mechanism, intended to discourage "red herring issues or issues that clearly do not justify a rate increase."¹⁴⁹ The OAG identified the Nuclear Stability Plan and the deferral and amortization of nuclear refueling outages as examples of "unconventional" issues that caused unreasonable expenditures of time and effort in this rate case.¹⁵⁰ The parties have acknowledged the difficulty of Xcel's position in making assumptions about life extension issues in advance of approval by any regulatory entity.¹⁵¹ The Nuclear Stability Plan was not a frivolous or imprudent proposal. With regard to the deferral-and-amortization methodology for recovering nuclear refueling outage costs, the OES recommended use of this method, and ultimately, so has the Administrative Law Judge. The Commission may disagree with these recommendations, but the proposal is clearly not frivolous or imprudent.

116. More fundamentally, the OAG's proposal to tie recovery of rate case expenses to the ultimately approved revenue requirement is arbitrary and unreasonable, in that the cost of presenting a rate case is not proportional to the requested increase.¹⁵² Many of the most difficult and time-consuming issues in this case, for example, pertain to rate design or other regulatory policy issues.

117. Alternatively, the OAG proposes treating rate case expenses as a "normal" expense.¹⁵³ The long-standing practice has been to recognize rate case expenses as a one-time expense that needs to be amortized over the number of years between rate cases.¹⁵⁴ Instead of amortizing the expense, the OAG proposes treating the rate case expense as if it were a "normal" ongoing

¹⁴⁸ Ex. 66 (Lindell Direct) at 49-51.

¹⁴⁹ OAG Initial Brief at 26.

¹⁵⁰ Ex. 68 (Lindell Surrebuttal) at 14.

¹⁵¹ Ex. 64 (Schedin Surrebuttal) at 5.

¹⁵² Ex. 15 (Heuer Rebuttal) at 51.

¹⁵³ Ex. 66, Lindell Direct at 49.

¹⁵⁴ See, e.g., Ex. 103 (Lusti Direct) at 13.

expense. The only purpose of this proposal would be to prevent Xcel from seeking to recover the unamortized balance in a future rate case.¹⁵⁵

118. Rate case expense is not a normal, annual expense. Amortization recognizes that the expense has occurred, historically, every four years. This is a methodical and accurate characterization of the expense. While recent Commission decisions have not allowed recovery of unamortized balances, the Administrative Law Judge does not believe the Commission has adopted a firm policy that unamortized rate case expenses are never to be recovered in any rate case under any circumstances.¹⁵⁶ It is not necessary to decide now whether future unamortized balances should be recoverable in a future case. In its Reply Brief, Xcel proposed that if it does not file a rate case within four years, it would defer the additional recovered expense at the rate of \$33,121 per month and credit this amount to offset its revenue requirement in the next rate case.¹⁵⁷ Although it seems likely that Xcel will bring its next rate case within four years, this approach would protect ratepayers from any possible over-recovery of this expense.

119. The Administrative Law Judge recommends that the Commission use Xcel's proposed rate case expense in the amount of \$1,593,811, to be amortized over four years, with the requirement that if Xcel does not bring a rate case within four years, expenses of \$33,121 per month will be deferred and credited to the revenue requirement in the next case.

C. Resolved Financial Issues

1. Advertising Expense

120. Xcel requested recovery of \$1,528,938 in test year costs relating to advertising.¹⁵⁸ The OES objected to inclusion of \$16,000 in costs associated with two advertisements, which were designed primarily to promote good will and Xcel's public image.¹⁵⁹ Xcel agreed to the adjustment, resulting in a revised test year advertising budget of \$1,512,938.¹⁶⁰

121. The MCC recommended that the portion of advertising expense related to printing on Xcel's billing envelopes be disallowed and suggested future limitations on such statements.¹⁶¹ The challenged message (relating to Xcel's development of wind energy) was printed from October 2007 to August 2008, and the cost of that message was not included in the test-year.¹⁶² Xcel agreed to provide further information in future rate cases regarding the steps taken to

¹⁵⁵ Xcel did not request a carrying charge on the unamortized balance of these expenses.

¹⁵⁶ See *Otter Tail Power Order* at 52-54.

¹⁵⁷ Xcel Reply Brief at 34.

¹⁵⁸ Ex. 13 (Heuer Direct) at AEH-1 Schedule 16, p. 1.

¹⁵⁹ Ex. 72 (Davis Direct) at 3-4.

¹⁶⁰ *Id.*; Ex. 15 (Heuer Rebuttal) at 43.

¹⁶¹ Ex. 64 (Schedin Surrebuttal) at 6.

¹⁶² Ex. 45 (Heuer Supplemental Hearing Statement) at 5.

exclude costs related to branding and other promotional activities, where cost recovery is not permitted by Minn. Stat. § 216B.16, subd. 8, or the Commission statement on policy and advertising.¹⁶³

2. Association Dues

122. Due primarily to the reintegration of Xcel's nuclear plants, the test-year costs attributable to association dues grew from \$1,217,552 in 2006 to \$8,907,633 in 2009.¹⁶⁴ After examining the data further, the OES accepted Xcel's explanation and recommended that the Commission approve \$8,907,633 in association dues for test year 2009.¹⁶⁵

123. The OAG asked that Edison Electric Institute (EEI) costs promoting legislation and trade organization activities be disallowed unless Xcel could demonstrate that ratepayers benefit from the EEI expenses.¹⁶⁶ Xcel explained that EEI's lobbying costs are not included in the revenue requirement and that the EEI performs a valuable support function in areas such as environmental and Regional Transmission Organization development and standards, among others.¹⁶⁷ Based on the explanation, it appears the OAG is no longer seeking an adjustment related to EEI expenses.¹⁶⁸

3. Capacity Costs

124. The OES requested an explanation of why Xcel's capacity costs and energy sales are not allocated in the same manner, based on Xcel's system-wide resource planning.¹⁶⁹ Xcel explained that the NSP System capacity costs are first allocated between the NSP-M and NSP-W systems based on the 36-month coincident peak demand allocator. Then, the amount of capacity allocated to NSP-M is allocated to Minnesota, North Dakota, South Dakota, and Wholesale based on the 12-month coincident peak demand allocator. With this formula, both capacity costs and energy sales are allocated on an NSP System-wide basis.¹⁷⁰ No party objected to use of this allocator.

125. In its Direct Testimony, the OES requested information to tie out contract data with the information Xcel provided in response to OES Information Request 193.¹⁷¹ Xcel explained the process by which it forecasts long-term capacity expense and compares actual invoiced and paid capacity costs to test year forecasted expenses, and provided a comparison for the five highest cost

¹⁶³ *Id.* at 5.

¹⁶⁴ Ex. 3 (Application, Vol. 4 (Work Papers)) at A11-5; Ex. 72 (Davis Direct) at 9 & Attachment CTD-7 at 2-4.

¹⁶⁵ Ex. 72 (Davis Direct) at 9-10.

¹⁶⁶ Ex. 67 (Lindell Rebuttal) at 21.

¹⁶⁷ Ex. 8 (Sparby Surrebuttal) at 6.

¹⁶⁸ See generally Ex. 28 (Lindell Surrebuttal).

¹⁶⁹ Ex. 85 (Campbell Direct) at 40.

¹⁷⁰ Ex. 15 (Heuer Rebuttal) at 27.

¹⁷¹ Ex. 85 (Campbell Direct) at 85-86.

long-term capacity contracts.¹⁷² Based on Xcel's explanation, the OES agreed with the proposed long-term capacity costs included in the test year for this rate case.¹⁷³

126. In its Direct Testimony, the OES recommended that \$6,902,869 in short-term capacity costs be excluded from this rate case.¹⁷⁴ Xcel accepted this recommendation with a small adjustment.¹⁷⁵ Xcel reduced its forecast of short-term capacity costs by \$6,661,189 by taking into consideration the Interchange Agreement, which the OES had not included in its analysis.¹⁷⁶ Xcel and the OES agreed that \$6,661,189 of the short-term capacity costs should be excluded from this rate case.¹⁷⁷

127. The OES recommended that the Commission require Xcel, in future rate cases, to provide a schedule of short-term and long-term capacity costs by contract and show how the capacity amounts were calculated.¹⁷⁸ Xcel accepted that recommendation.¹⁷⁹

4. Charitable Contributions

128. Xcel requested recovery of \$1,568,947 in expenses, an amount equal to 50% of corporate charitable contributions benefiting the State of Minnesota.¹⁸⁰ The OES found these charitable contribution expenses to be reasonable and agreed that Xcel should recover \$1,568,947 associated with charitable contributions.¹⁸¹

5. Chemical Expense

129. The OES recommended that Xcel reduce test-year chemical costs by \$1,630,446 due to a decrease in commodity prices for the King plant and a reduced quantity for the High Bridge plant.¹⁸² Xcel proposed a reduction of \$1,367,665 for the Minnesota jurisdiction in order to reflect the portion of chemical costs allocated to NSP-W.¹⁸³ Since chemical costs are production-(generation-) related costs, it is necessary to allocate a portion of this cost reduction to NSP-W under the Interchange Agreement to reflect the impact of

¹⁷² Ex. 25 (Horneck Rebuttal) at 2-7 & Ex. (DGH-2), Schedule 3.

¹⁷³ Ex. 101 (Campbell Surrebuttal) at 14-15.

¹⁷⁴ Ex. 85 (Campbell Direct) at 39.

¹⁷⁵ Ex. 24 (Beuning Rebuttal) at 4-5.

¹⁷⁶ Ex. 15 (Heuer Rebuttal) at 26.

¹⁷⁷ Ex. 108 (Campbell Summary Statement); Ex. 15 (Heuer Rebuttal) at 25-26.

¹⁷⁸ Ex. 85 (Campbell Direct) at 86.

¹⁷⁹ Ex. 15 (Heuer Rebuttal) at 27.

¹⁸⁰ Ex. 13 (Heuer Direct) at 88.

¹⁸¹ Ex. 72 (Davis Direct) at 11-12.

¹⁸² Ex. 103 (Lusti Direct) at 20.

¹⁸³ Ex. 15 (Heuer Rebuttal) at 17.

reduced revenues from NSP-W.¹⁸⁴ The OES agreed with Xcel's proposed reduction of \$1,367,665, and the parties consider the issue resolved.¹⁸⁵

6. Conservation Expense

130. In its original filing, Xcel proposed recovering \$54,320,055 in Conservation Improvement Program (CIP) costs.¹⁸⁶ Xcel revised its requested CIP recovery downward by \$541,978 to \$53,778,076, reflecting an additional project modification that was not incorporated into its initial filing.¹⁸⁷ The OES reviewed the revised estimate of CIP costs and recommended approval of 2009 test-year CIP expenses of \$53,778,076.¹⁸⁸ Based on the OES recommendation to accept Xcel's sales forecast, the OES calculates this amount as \$53,778,076/32,483,817 MWh or \$1.65553 per MWh.

7. Demand Meter Readings

131. After its initial filing, Xcel discovered some of its Automated Meter Reading (AMR) demand meters failed to take demand readings on all days.¹⁸⁹ It estimated the impact of these missed readings on test year billing demand units and revenues¹⁹⁰ and found test year revenue should be adjusted upward by \$234,000.¹⁹¹ The OES agreed that test year revenue should be increased by \$234,000.¹⁹²

8. Economic Development Expense

132. Xcel requested recovery of 50% of its Minnesota economic development expenses, in the amount of \$81,241.¹⁹³ After conducting a ratepayer impact test, the OES determined that Xcel's economic development spending was cost effective and therefore should be approved at the requested level of \$81,241.¹⁹⁴

9. Employee and Board of Directors Expense

133. The OAG raised a number of concerns with regard to Xcel's employee and Board of Directors expenses.¹⁹⁵ The parties met to discuss settlement of the issues on a number of occasions. Xcel initially proposed a 20%

¹⁸⁴ *Id.*

¹⁸⁵ Ex. 107 (Lusti Surrebuttal) at 4.

¹⁸⁶ Ex. 36 (Zins Direct) at 13-14.

¹⁸⁷ Ex. 72 (Davis Direct) at 12, CTD-9; see also Ex. 15 (Heuer Rebuttal) at 43.

¹⁸⁸ Ex. 72 (Davis Direct) at 12-13.

¹⁸⁹ Ex. 41 (Huso Rebuttal) at 22.

¹⁹⁰ *Id.* at SVH-2.

¹⁹¹ *Id.* at 23.

¹⁹² Ex. 107 (Lusti Surrebuttal) at 11-12.

¹⁹³ Ex. 13 (Heuer Direct) at 85; Ex. 3 (Vol. 4 of Working Papers) at A8-1.

¹⁹⁴ Ex. 72 (Davis Direct) at 6, 8.

¹⁹⁵ Ex. 67 (Lindell Rebuttal) at 2-23, Ex. 68 (Lindell Surrebuttal) at 2-6.

overall reduction in test-year employee expenses of \$1.9 million¹⁹⁶ and a reduction of \$1.063 million in specific expense items to address the OAG's concerns.¹⁹⁷ The reduction of \$1.063 million removed all 2008 actual executive employee expenses from the 2009 cost of service, removed actual 2008 costs from the test-year for employee recognition meals and customer entertainment, and placed caps of \$250 on hotel rooms and meal costs. After further settlement discussions with the OAG, Xcel proposed an additional reduction of \$924,000 to test-year employee expenses.¹⁹⁸ This adjustment reflects reduced caps of \$200 for meal costs and \$150 for hotel rooms, a reduction in Board of Directors retreat expenses, a reduction to employee recognition expenses not related to safety, an adjustment for small value expenses, a reduction in Board of Directors compensation, and removal of executive perquisite costs.¹⁹⁹ Total proposed adjustments to test-year employee and Board of Directors expenses are \$3.862 million.²⁰⁰

134. In addition to the proposed adjustments to test-year expenses, Xcel also agreed to revise its employee expense and related policies.²⁰¹ The terms of its plan for these revisions are outlined in the Employee Expense Compliance Plan.²⁰² Xcel will provide the OAG and any other interested parties a copy of the revised employee expense and related policies.²⁰³ After receiving feedback from the OAG and any other interested parties, Xcel will then submit a filing to the Commission to initiate a full review and comment process on the appropriateness of the revised policies and the proposed regulatory accounting treatment for employee expenses. The filing will outline how the policy seeks to ensure that above-the-line expenses are reasonable and necessary for the provision of utility services for Minnesota ratepayers.²⁰⁴ Xcel will also provide, within a timeframe agreed upon by parties, a report to the Commission regarding the effect the changes have had on employee expenses.²⁰⁵ The OAG considers this issue resolved.

10. Fleet Fuel Expenses

135. Xcel developed the test-year budget for fleet fuel costs based on a blended rate of \$3.83 per gallon,²⁰⁶ which was calculated using the price of gasoline futures on May 14, 2008;²⁰⁷ however, Xcel also executed hedges for a

¹⁹⁶ Ex. 15 (Heuer Rebuttal) at 19.

¹⁹⁷ *Id.* at 21.

¹⁹⁸ Ex. 17 (Heuer Surrebuttal) at 32.

¹⁹⁹ *Id.* at 31-32.

²⁰⁰ *Id.* at 33.

²⁰¹ Ex. 45 (Heuer Supplemental) at 3 & (AEH-4), Schedule 2.

²⁰² *Id.* at Schedule 2.

²⁰³ *Id.*

²⁰⁴ *Id.*

²⁰⁵ *Id.*

²⁰⁶ *Id.*

²⁰⁷ Ex. 103 (Lusti Direct) at 20.

portion of its 2009 fuel requirements.²⁰⁸ Based on execution of these hedges, the OES recommended that Xcel reduce test-year fleet fuel expenses by \$366,498.²⁰⁹ The OES adjustment reflects the lower hedged cost of gasoline and the lower current cost of unleaded gasoline and diesel fuel.²¹⁰ Xcel agreed to the adjustment.²¹¹ The OES and Xcel consider this issue resolved.

11. Incentive Compensation

136. Using the methodology the Commission ordered in Xcel's last rate case, Xcel initially proposed setting test year incentive compensation at 83% of target, based on the four-year historical average of actual payouts, covering 2004 to 2007.²¹² This method excludes long-term incentive compensation and other bonuses, incentives, and incentive compensation exceeding 25% of base compensation. Because Xcel did not pay any incentive compensation in 2008, the OES proposed including that year by using a four-year average from 2005 to 2008. This calculation lowered the historic average to 70 percent of target and reduced the incentive compensation included in the test year by \$2,531,619.²¹³ Xcel accepted the adjustment for the purpose of resolving the incentive compensation in this rate case. The refund mechanism in place for the past several rate cases would continue to apply, so if actual incentive compensation paid in 2010 (or future years) is less than the test year level, Xcel would refund the difference to Minnesota electric customers.²¹⁴

12. Interest Synchronization

137. The interest deduction applicable to the income tax calculation is the result of a calculation commonly referred to as "interest synchronization."²¹⁵ The OES agreed with the mechanics of Xcel's initial interest synchronization calculation, but also observed the calculation must be performed any time a change in rate base, weighted cost of debt, or operating income occurs.²¹⁶ Xcel agreed with this observation and committed to recalculating interest synchronization when the final adjustments to rate base, weighted cost of debt, and operating income are determined.

13. Joint Zonal Transmission Expense

138. In its Direct Testimony, the OES proposed correcting an error in Xcel's joint zonal transmission expense, resulting in a \$1,970,019 downward

²⁰⁸ *Id.*

²⁰⁹ Ex. 103 (Lusti Direct) at 22.

²¹⁰ Ex. 15 (Heuer Rebuttal) at 18.

²¹¹ Ex. 15 (Heuer Rebuttal) at 18.

²¹² Ex. 30 (McDaniel Direct) at 13-14.

²¹³ Ex. 103 (Lusti Direct) at 10-11.

²¹⁴ Ex. 15 (Heuer Rebuttal) at 14-15.

²¹⁵ Ex. 13 (Heuer Direct) at 34.

²¹⁶ Ex. 103 (Lusti Direct) at 26.

adjustment.²¹⁷ Xcel accepted this correction.²¹⁸ Xcel also noted two recent changes that affect the transmission revenues and expenses: (1) Great River Energy's switch from historical to forecasted joint zonal revenues and expenses under MISO Attachment O formula transmission rates; and (2) a new Joint Zonal Agreement between Xcel Energy and Great River Energy taking effect on July 1, 2009. The result of those two changes and the agreed upon correction from the OES Direct Testimony have a net effect of reducing the Joint Zonal Transmission expense by \$116,392.²¹⁹ The OES concurred with these adjustments.²²⁰

14. Manufacturer's Production Tax Deduction

139. Xcel initially proposed a \$57,000 tax deduction attributable to the Manufacturer's Production Tax deduction.²²¹ Xcel subsequently revised its deduction upward to \$66,000.²²² The OES agreed with the revised deduction and recommended the Commission approve the decrease in test year taxes by \$66,000.²²³ The final value of the Manufacturer's Production Tax deduction will need to be recalculated during the compliance filing.²²⁴

15. Recovery of Unamortized Expenses

140. As noted above, the OES and OAG recommended disallowing Xcel's unamortized rate case expenses from the last general electric rate case, which decreases test-year amortization expenses by \$99,400.²²⁵ Xcel agreed to this adjustment.²²⁶ In recent cases, the Commission has not allowed recovery of unamortized rate case test-year expenses in a subsequent rate case.²²⁷ Therefore, this adjustment is consistent with Commission precedent. The parties consider this issue resolved.

141. The OES also proposed to disallow recovery of the unamortized balances of five items from the last rate case: the Income Tax Tracker; the E002/M-05-1471 Deferred Accounting Tax treatment; the Time-of-Use Study; the Levee Station Site; and the Minnesota Emissions allowance.²²⁸ Xcel provided evidence that these five unamortized balances were all items that had been deferred from periods before the 2006 test year for later recovery or credit in base rates. Therefore, there is no test year matching policy reason for not

²¹⁷ Ex. 85 (Campbell Direct) at 44, 86.

²¹⁸ Ex. 15 (Heuer Rebuttal) at 22-23.

²¹⁹ *Id.* at 23-24. This is the net result of increasing operating revenues by approximately \$3,270,000 and increasing transmission expense by \$3,154,000.

²²⁰ Ex. 101 (Campbell Surrebuttal) at 15-16.

²²¹ Ex. 13 (Heuer Direct) at 107.

²²² Ex. 15 (Heuer Rebuttal) at AEH-2 Schedule 2, p. 4.

²²³ Ex. 107 (Lusti Surrebuttal) at 12.

²²⁴ Ex. 15 (Heuer Rebuttal) at 14.

²²⁵ Ex. 103 (Lusti Direct) at 15-16.

²²⁶ Ex. 15 (Heuer Rebuttal) at 15.

²²⁷ *Id.*

²²⁸ Ex. 103 (Lusti Direct) at 16-18.

allowing recovery/credit of the unrecovered deferred expenses or credits in this rate case. In the aggregate, allowing the unrecovered balances to be included in the current revenue requirement decreases that revenue requirement by \$134,000.²²⁹ The OES does not oppose recovery of these five items in resolution of this rate case.²³⁰

16. Renewable Energy Credits

142. The MCC proposed that any Renewable Energy Credits (RECs) be recognized in the year they are created and returned to the ratepayers.²³¹ Xcel explained that the creation of RECs does not create revenue; RECs only have value if they are sold. Xcel Energy has no expectation of selling its RECs, but is instead keeping them to fulfill Renewable Energy Standards mandated in various jurisdictions. Xcel agrees that if it does sell its RECs, the revenue received should be credited to the RES Rider and flowed to its customers.²³² During the hearings, MCC agreed that Xcel's statements adequately addressed its proposal.²³³

17. Research and Development Expense

143. Xcel requested cost recovery on \$1,604,637 in research and development expenses.²³⁴ The OES reviewed these expense items and found they were all consistent with Commission policy and ratepayer interests.²³⁵ The OES recommended approval of \$1,604,637 for annual research and development expenses in the test year.²³⁶

18. Sales Forecast

144. The OES initially raised concerns about Xcel's use of econometric models that use economic and demographic data obtained from a third-party vendor as independent variables in its test year sales forecast.²³⁷ Because it could not verify the accuracy of the data, the OES proposed a revenue adjustment that was developed without the use of econometric information.²³⁸ Xcel responded by providing further information on the econometric data it had

²²⁹ Ex. 15 (Heuer Rebuttal) at 15-16.

²³⁰ Ex. 107 (Lusti Surrebuttal) at 3.

²³¹ Ex. 61 (Schedin Direct) at 27.

²³² Ex. 15 (Heuer Rebuttal) at 54.

²³³ Tr. 3:26-27 (Schedin).

²³⁴ Ex. 72 (Davis Direct) at 14.

²³⁵ *Id.* at 15.

²³⁶ *Id.*

²³⁷ Ex. 73 (Ham Direct) at 11-12.

²³⁸ *Id.*

relied upon.²³⁹ Based on that further information, the OES accepted Xcel's test year sales forecast and withdrew its proposed adjustment.²⁴⁰

145. Xcel also agreed to continue working with the OES on forecasting issues. While Xcel maintains it cannot always meet a requirement to independently verify or duplicate all economic and demographic data obtained from third parties, it committed to working with the OES toward greater data transparency and will work closely with the OES to respond to any concerns regarding its data sources.²⁴¹

146. Pursuant to the Commission's September 1, 2006, Order in Xcel's last electric rate case (Docket No. E002/GR-05-1428), Xcel submitted its data used in test year sales forecasts 30 days before it filed this rate case. It will comply with a similar requirement, if ordered in this rate case, and will work with the OES to facilitate its consideration and discovery of test year forecasts in future rate cases.²⁴²

147. The OES recommended that Xcel continue to maintain and monitor various resources such as the "Financial and Rate Revenue" report and "Tariff Analysis Report" discussed in the compliance report submitted on September 4, 2007 in Docket No. E002/GR-05-1428, and the "Graybar" report and "Active Service Count" report referenced in its response to OES Information Request No. 15 in this proceeding.²⁴³ Xcel agreed that these reporting tools help ensure the integrity of its billing system sales volumes and customer counts and also assist it in flagging and reconciling irregularities. Xcel intends to continue using and refining these reports to that end.²⁴⁴

148. The OES recommended that the Commission require Xcel to continue working with the OES on improving the electronic linkage between CCOSS, forecasting and revenue models for its next rate case.²⁴⁵ Xcel agreed that it will continue improving those linkages and coordinating its efforts with the OES. Xcel believes that future improvements are likely to focus less on improving linkages and more on documenting and automating the data development stages within individual models.²⁴⁶

19. Vegetation Management

149. The OES recommended reducing Xcel's test-year vegetation management expenses by \$2,220,942.²⁴⁷ This adjustment is based on the

²³⁹ Ex. 12 (Marks Rebuttal) at 2-8 and JEM-2, Schedule 1.

²⁴⁰ Ex. 107 (Lusti Surrebuttal) at 7.

²⁴¹ Ex. 12 (Marks Rebuttal) at 9.

²⁴² *Id.*

²⁴³ Ex. 73 (Ham Direct) at 9.

²⁴⁴ Ex. 12 (Marks Rebuttal) at 10.

²⁴⁵ Ex. 73 (Ham Direct) at 14-15.

²⁴⁶ Ex. 41 (Huso Rebuttal) at 5-6.

²⁴⁷ Ex. 103 (Lusti Direct) at 19.

difference between its budgeted increase and the actual compounded annual average increase in vegetation management expenses from 2006 through 2008.²⁴⁸ Xcel agreed to this adjustment.²⁴⁹

20. Wage and Benefit Costs

150. *Base Salaries.* The OES recommended that Xcel reduce its 2009 base salary expense by \$4,811,713, which is the amount of Xcel's budgeted (but not implemented) 3.75% merit increase for non-bargaining employees.²⁵⁰ Xcel agreed to the adjustment.²⁵¹ The OES and Xcel consider this issue resolved.²⁵²

151. *Health Care.* In its Rebuttal Testimony, Xcel proposed an adjustment of \$3,846,000 in the Minnesota retail electrical jurisdiction for the increase in health and welfare costs for its current employees, due to the increased number of employees and an approximately 8% cost increase per individual.²⁵³ Xcel filed its workpapers supporting this adjustment.²⁵⁴ The OES agreed to this adjustment.²⁵⁵

152. *Pension Costs.* Because of changes in market performance since the 2009 budget was prepared, Xcel recalculated the benefits costs for pension expense in its Rebuttal Testimony, which resulted in a \$907,377 increase to the pension expense.²⁵⁶ Xcel filed its workpapers supporting this adjustment.²⁵⁷ The OES accepted the new pension expense.²⁵⁸

21. Wholesale Margins

153. *Asset Based Margins.* Xcel requested retention of the existing crediting methodology, under which 100% of the asset based margins are credited to the fuel cost revenue requirement and passed through the Fuel Clause Adjustment (FCA). This mechanism is appropriate because the amount of asset based margins is too volatile to establish a reasonable fixed credit, particularly in light of the addition of approximately 560 MWs of wind resources to the NSP system between 2006 and 2008, and the MISO market has seen the overall installed wind generation expand to more than 5,000 MW, a trend which increases the overall market volatility.²⁵⁹ Xcel also provided testimony that based

²⁴⁸ Ex. 103 (Lusti Direct) at 19.

²⁴⁹ Ex. 45 (Heuer Supplemental) at 1.

²⁵⁰ Ex. 103 (Lusti Direct) at 23 & Attachment DVL-16 (Xcel Energy's Response to OES Information Request No. 160, Attachment A).

²⁵¹ Ex. 15 (Heuer Rebuttal) at 19.

²⁵² Ex. 107 (Lusti Surrebuttal) at 4-5.

²⁵³ Ex. 15 (Heuer Rebuttal) at 19-20; Ex.31 (McDaniel Rebuttal) at 2-7.

²⁵⁴ Ex. 45 (Heuer Supplemental Hearing Statement) at 1.

²⁵⁵ Ex. 107 (Lusti Surrebuttal) at 9 & (DVL-S-7), Column (s.2).

²⁵⁶ Ex. 15 (Heuer Rebuttal) at 20-21.

²⁵⁷ Ex. 45 (Heuer Supplemental Hearing Statement) at 1.

²⁵⁸ Ex. 107 (Lusti Surrebuttal) at 9 & (DVL-S-7), Column (s.4).

²⁵⁹ Ex. 49 (Beuning Supplemental Hearing Statement) at 2-3.

on its plans to further increase the amount of wind on its system in 2010 and 2011, the uncertainty in forecasting and the inherent variability of this resource will create even greater volatility in asset based margins in the future.²⁶⁰ Xcel, OES, and MCC agree that asset based margins should continue to be credited to the ratepayers through the fuel clause adjustment. No change in procedures is being requested by any party.²⁶¹

154. Xcel agrees to continue to provide the current reporting in the monthly FCA filings and the September 1 Annual Automatic Adjustments (AAA) of Charges reports. Xcel will also work with the OES if the OES believes additional reporting is needed.

155. *Non-Asset Based Margins.* Xcel and OES agree that Xcel shall continue to credit 25% of the margins from non-asset based transactions to the FCA and retain 75% of those margins. There is no change to the current procedure.²⁶²

156. Xcel commits to providing a fully allocated cost study that demonstrates the fully allocated cost of obtaining non-asset based margins along with an incremental cost study.²⁶³

157. *ASM Recovery.* As established for the interim rate period in this proceeding, Xcel, OES, and MCC agree that 100% of the margins for ancillary services resulting from the start of the MISO Ancillary Services Market (ASM) in January 2009 should be credited to ratepayers through the fuel clause adjustment.²⁶⁴

158. In its Direct Testimony, the OES maintained that the FCA Tariff Sheet No. 91.2 should be amended to reference the fact that 100% of the ancillary service margins are shared with the ratepayers.²⁶⁵ Xcel agreed to make this change in the tariff language.²⁶⁶

V. COST OF CAPITAL

159. Xcel recommended an overall rate of return (ROR) of 8.89%, including a return on equity (ROE) of 11.00%.²⁶⁷ OES recommended an overall ROR of 8.83%, including an ROE of 10.88%.²⁶⁸

²⁶⁰ *Id.*

²⁶¹ *Id.* at 1; Tr. 3:164 (Campbell); Ex. 63 (Schedin Rebuttal) at 8; Tr. 1:42.

²⁶² Ex. 49 (Beuning Supplemental Hearing Statement) at 3; Tr. 3:164 (Campbell); Ex. 108 (Campbell Summary Statement) at 2; Ex. 63 (Schedin Rebuttal) at 8.

²⁶³ Ex. 45 (Heuer Supplemental Hearing Statement) at 2-3.

²⁶⁴ Ex. 49 (Beuning Supplemental Hearing Statement) at 1; Tr. 3:164 (Campbell).

²⁶⁵ Ex. 77 (Ouanes Direct) at 4-5; Ex. 85 (Campbell Direct) at 65-66.

²⁶⁶ Ex. 38 (Zins Rebuttal) at 6-7.

²⁶⁷ Ex. 27 (Tyson Direct) at 2.

²⁶⁸ Ex. 82 (Amit Direct) at 51; Ex. 109 (Amit Summary Statement) at 3.

A. Capital Structure

160. Northern States Power Company, a Minnesota corporation (NSP-M), is a wholly owned subsidiary of Xcel Energy, Inc. It is a separate legal entity from Xcel Energy that has its own capital structure and issues its own debt securities. NSP-M files annual and quarterly 10-K and 10-Q statements with the SEC, as well as registration statements that allow its long-term debt securities to be traded in the financial markets.²⁶⁹ In addition to internally-generated funds, NSP-M finances its business with a combination of short-term debt, long-term debt and common equity, which comprise its capital structure.²⁷⁰

161. Xcel's proposed capital structure and weighted cost of capital for NSP-M for the test year (calendar year 2009) are as follows:²⁷¹

<u>Capitalization</u> <u>Cost</u>	<u>Percentage of</u> <u>Total Capitalization</u>	<u>Cost</u>	<u>Weighted</u>
Long-term Debt	46.25%	6.61%	3.06%
Short-term Debt	1.28%	4.41%	0.06%
<u>Common Equity</u>	<u>52.47%</u>	11.00%	<u>5.77%</u>
Total	100.00%		8.89%

The long-term debt balance, the cost of debt, and the common equity were adjusted to reflect the Commission's March 8, 2004 Order in the Metropolitan Emissions Reduction Project (MERP), Docket No. E002/M-02-633.²⁷² The cost of long-term debt also includes the adjustment to eliminate any possible adverse impact from the investment in NRG Energy that was reviewed and approved by the Commission in Docket Nos. E002/GR-05-1428 and G002/GR-04-1511.²⁷³

162. Xcel's proposed capital structure ratios fall within the range of the ratios for the proxy utility company group analyzed by John Reed of Concentric Energy Advisors, Inc.²⁷⁴ The proposed long-term debt ratio is lower than the average long-term debt ratio for the final electric comparison group analyzed by Dr. Eilon Amit of OES and is well inside that group's long-term debt ratio range.²⁷⁵ Moreover, Standard & Poor's expects a BBB rated company to maintain a debt ratio in the range of 50-60%, demonstrating that Xcel's long-term debt ratio represents a lower financial risk than that of a typical electric utility with a BBB bond rating.²⁷⁶ The proposed 52.47% equity ratio is within the S&P target range for a BBB+ senior unsecured rating and is comparable to other A/BBB

²⁶⁹ Ex. 9 (Reed Direct) at 16; Ex. 27 (Tyson Direct) at 10; Ex. 82 (Amit Direct) at 46.

²⁷⁰ Ex. 27 (Tyson Direct) at 10-11.

²⁷¹ *Id.*, Schedule 2.

²⁷² *Id.* at 13, 15-18; Ex. 82 (Amit Direct) at 46.

²⁷³ Ex. 27 (Tyson Direct) at 13.

²⁷⁴ Ex. 9 (Reed Direct) at 53-54 & Schedule 9.

²⁷⁵ Ex. 82 (Amit Direct) at 47.

²⁷⁶ *Id.*

rated utilities.²⁷⁷ While Xcel's proposed equity ratio is somewhat higher than that of a typical electric utility, OES determined that it is still a reasonable equity ratio.²⁷⁸

163. As discussed more fully below, the OES disagrees with the cost and weighted cost of common equity and the overall rate of return proposed by Xcel; however, the OES otherwise agreed with Xcel that the proposed capital structure for NSP-M is appropriate, including the MERP adjustments.²⁷⁹ No other party disputed the capital structure proposed by Xcel and concurred in by OES.

B. Cost of Short-Term Debt

164. Xcel proposed a 4.41% cost of short-term debt, based on the 2009 forecast for the London Interbank Offered Rate (LIBOR) from Global Insight released August 27, 2008, adjusted for dealer issuance fees and market spread.²⁸⁰

165. The OES agreed with Xcel's methodology and calculations and concurred that this is the appropriate short-term cost of debt. Due to the existing economic crisis, OES agreed that the current LIBOR rates should not be used in this proceeding.²⁸¹ No other party objected to the methodology or calculations.

166. In connection with the Commission's Order in Docket No. E002/AI-04-100, Xcel provided testimony attesting that the affiliated interest agreement for the Utility Money Pool continued to be consistent with the public interest because it adds to the financing alternatives available to each utility participant without limiting access to the participant's existing financing. It also provided evidence regarding Utility Money Pool activity from September 2007 through August 2008.²⁸²

C. Cost of Long-Term Debt

167. Xcel proposed a 6.61% cost of long-term debt, based upon the average 12-month balances for the period January 2009 through December 2009 and several adjustments to reflect potential costs related to the bankruptcy of NRG, the lack of tax benefits from City of Becker's issuance of Pollution Control Revenue Bonds relating to NSP's Sherburne County Generating Station prior to August 2002, and the forecasted debt cost applied under the MERP Settlement.²⁸³

²⁷⁷ Ex. 27 (Tyson Direct) at 15.

²⁷⁸ Ex. 82 (Amit Direct) at 47-48.

²⁷⁹ *Id.* at 46-47.

²⁸⁰ Ex. 27 (Tyson Direct) at 11.

²⁸¹ Ex. 82 (Amit Direct) at 48-49; Ex. 109 (Amit Summary Statement) at 3.

²⁸² Ex. 27 (Tyson Direct) at 12 & Schedule 3A.

²⁸³ *Id.* at 13; Schedules 4A-4C; Ex. 82 (Amit Direct) at 49-50.

168. In Xcel's last electric rate case, the cost of long-term debt was 7.08%, or 47 basis points higher than its current proposal.²⁸⁴

169. The OES agreed that Xcel's calculations and testimony regarding the adjustments are reasonable and that its proposed cost of long-term debt of 6.61% is reasonable.²⁸⁵ No other party objected to Xcel's methodology or calculations.

D. Return on Equity

170. Xcel and OES disagreed concerning the appropriate Return on Equity (ROE) in this matter. Xcel recommended an 11.00% ROE, while OES recommended a 10.88% ROE. While there are some differences in the methodologies relied upon by Xcel and OES, their respective methodologies resulted in generally similar results.

171. The primary points of disagreement between Xcel and the OES involve the utilities to be used as the group of comparable utilities for determining the cost of equity for NSP-M, and the appropriateness of using a constant growth Discounted Cash Flow (DCF) model for certain companies in Xcel's group of comparables.

172. Xcel and OES agreed on several other matters, including placing primary reliance on the DCF model and limiting use of the Capital Asset Pricing Model (CAPM) to comparison with DCF results; including one-half year of growth in the calculation of the dividend yield for the DCF model; using projected earnings per share growth rates to determine the growth rate in the DCF model; using stock prices ending September 30, 2008, in calculating the dividend yield due to recent market volatility; and incorporating flotation cost recovery.

173. The DCF model is widely used in regulatory proceedings to determine the cost of equity for regulated utilities. The DCF model is based on the theory that a stock's current market price represents the present value of all future expected cash flows.²⁸⁶

174. Under the constant growth DCF method, if annual dividends grow at a constant rate over an infinite period, the required rate of return on common equity capital is estimated using the following formula: The expected (required) rate of return on equity = the expected dividend yield + the expected growth rate in dividends.²⁸⁷

175. Another DCF method is the Two Growth Rates DCF (TGD CF). That approach is used when the short-term growth rate is unlikely to be

²⁸⁴ Ex. 27 (Tyson Direct) at 14.

²⁸⁵ Ex. 82 (Amit Direct) at 50-51.

²⁸⁶ Ex. 9 (Reed Direct) at 23-24.

²⁸⁷ Ex. 82 (Amit Direct) at 4-5; Ex. 9 (Reed Direct) at 24.

sustained in the long run. The TGDCF assumes that, for a relatively short time period, earnings and dividends may grow annually at a different rate than the long-term, sustainable growth rate and, at the end of this short period, both earnings and dividends will grow at a constant, sustainable annual rate.²⁸⁸

176. The CAPM is a risk premium approach that specifies the required ROE for a given security as a function of the risk-free rate of return, plus a risk premium that represents the non-diversifiable risk of the security.²⁸⁹ To perform a CAPM analysis, it is necessary to determine the return on a riskless asset, along with the appropriate beta (which measures the systematic risk of the stock) and the appropriate required rate of return on the market portfolio.²⁹⁰ The use of the CAPM raises some complex issues, including difficulties in determining the appropriate beta, the appropriate riskless asset, the appropriate risk premium, and the effect of taxes.²⁹¹

1. Xcel's Proposed ROE

177. Xcel's proposed ROE of 11.00% was based on the constant growth form of the DCF model, the CAPM, and the Risk Premium approach.²⁹² Xcel's analysis placed more emphasis on the constant growth form of the DCF model than on the other models and used the CAPM and the Risk Premium approach as a means of assessing the reasonableness of its DCF results.²⁹³ Although Xcel's expert witness on ROE, John Reed, recommended an ROE in the range of 11.00% to 12.00%, Xcel requested a ROE of 11.00% based upon its view that the capital markets will have stabilized by the time the Commission decides this case.²⁹⁴

178. To assist in estimating the ROE for NSP-M, Mr. Reed developed a proxy group of vertically-integrated electric utilities who met certain screening criteria. Mr. Reed began with companies that Value Line classifies as Electric Utilities, which includes a group of 57 domestic U.S. utilities. He then excluded from the group the following: companies whose beta estimates from Value Line and Bloomberg fell outside of one standard deviation of the group average; companies that have not been covered by at least two generally recognized utility industry equity analysts; companies that had senior bond and/or corporate ratings below BBB-; companies that do not pay cash dividends, because such companies cannot be analyzed using the DCF model; companies that do not own regulated generation assets; companies whose regulated revenues and net income comprise less than 60% of the respective totals for the company; companies whose regulated electric revenues and net income represented less

²⁸⁸ Ex. 82 (Amit Direct) at 5-6, 26.

²⁸⁹ Ex. 9 (Reed Direct) at 31.

²⁹⁰ Ex. 82 (Amit Direct) at 37.

²⁹¹ *Id.*

²⁹² *Id.* at 3, 21.

²⁹³ *Id.* at 23, 30.

²⁹⁴ Ex. 6 (Sparby Direct) at 4; Ex. 9 (Reed Direct) at 2-3.

than 90% of total regulated revenues and net income to ensure a focus on companies whose revenues and net income are derived primarily from electric operations; and companies that are currently known to be party to a merger.²⁹⁵

179. The screening criteria eliminated 45 of the 57 companies considered for inclusion in the proxy group. Xcel itself was not included in the proxy group since it did not derive at least 90% of its revenues from regulated electric service. The 12 companies ultimately included in Mr. Reed's primary proxy group were American Electric Power, Cleco Corp., Edison International, Empire District Electric, Entergy Corp., FPL Energy, IDACORP, Inc., Northeast Utilities, Pinnacle West, Portland General, Progress Energy, Inc., and Westar Energy.²⁹⁶ Mr. Reed also used an expanded comparison group of 17 utilities who derive at least 60 percent of their revenues from regulated electric service as a check on reasonableness.²⁹⁷

180. Mr. Reed used the proxy companies' current dividends and average closing stock prices over three separate periods of time (the most recent 30 trading days, the most recent 90 trading days, and the most recent 180 trading days ended September 30, 2008) to determine the dividend yield component of the DCF model. Because of unprecedented volatility in the equity market during October 2008, he did not extend his data past September 30, 2008.²⁹⁸ Since utility companies tend to increase their quarterly dividends at different times throughout the year, Mr. Reed assumed that such increases would be evenly distributed over calendar quarters. To reflect this assumption, he applied one-half of the expected annual dividend growth for the purposes of calculating the expected dividend yield component of the DCF model.²⁹⁹ He determined that growth in earnings per share (EPS) represented the most reasonable measure of long-term growth of a company, and did not include expected dividend growth rates or book value growth projections in the growth rate component of his DCF model.³⁰⁰ Because it is conventional practice to rely on analysts' forecasts as the basis of growth rate projections, Mr. Reed examined the earnings growth forecasts provided by Value Line and Zacks.³⁰¹ He thereafter applied the DCF model to the 12-company primary proxy group using the average daily closing prices for the 30-, 90-, and 180-trading days ended September 30, 2008; the annualized dividend per share as of September 30, 2008; and the average of the Zacks and Value Line company-specific earnings growth forecasts.³⁰²

²⁹⁵ Ex. 9 (Reed Direct) at 16-17.

²⁹⁶ *Id.* at 16-17.

²⁹⁷ *Id.* at 17.

²⁹⁸ *Id.* at 25-26.

²⁹⁹ *Id.* at 26.

³⁰⁰ *Id.* at 27-28.

³⁰¹ *Id.* at 28-29.

³⁰² *Id.* at 29.

181. Mr. Reed calculated a range of DCF results. The high mean DCF result used the maximum growth rate (i.e., the higher of the Value Line EPS and the Zacks EPS growth rates) in combination with the expected dividend yield for each of the proxy group companies, and reflected the average maximum DCF result for the proxy group. The low mean result used the lower of the Value Line EPS and the Zacks EPS growth rates for each company. The mean DCF results used the average of the Value Line and Zacks EPS growth rates in combination with the expected dividend yield for each company.³⁰³

182. Prior to adjustment for the effect of flotation costs, Mr. Reed's mean DCF results for his primary 12-company proxy group for the 30-day and 90-day averaging period were 11.95%, and his results for the 180-day averaging period were 11.88%.³⁰⁴

183. To assess the reasonableness of the DCF results, Mr. Reed used the CAPM and the Risk Premium approaches.³⁰⁵ Mr. Reed's unadjusted mean CAPM results ranged from 10.29% to 10.63%, before consideration of flotation costs. Mr. Reed testified that the CAPM results were so far below the DCF results because the CAPM results are being driven down by the decline in yields on treasury bonds.³⁰⁶ Mr. Reed's Risk Premium analysis using historical measures of the Moody's Baa rated utility bond index yield showed that the ROE would range from 10.78% to 10.92%, which is at the lower end of the range of results from Xcel's DCF analyses.³⁰⁷

184. In Mr. Reed's opinion, the Risk Premium data as of September 30, 2008 (the last day of the data used in Xcel's Risk Premium analysis) does not necessarily reflect the rates that utility companies currently have to pay in order to complete a financing. He noted that Ohio Edison and AmerenIP issued utility debt in October of 2008 at effective yields of 8.50% and 10.00%, respectively, and pointed out that these interest rates were 141 to 291 basis points above the 30-day average of the comparable Moody's Baa Utility Bond Index as of September 30, 2008, which was 7.09%. Using an 8.50 percent rate of current long-term debt, the risk premium is 3.17% and the ROE is 11.67%; using the 10.00% rate, the risk premium is 2.46% and the ROE is 12.46%. Mr. Reed believes that the current financial environment is relevant in forming his recommended range of results.³⁰⁸

185. Flotation costs are costs associated with the sale of new issues of common stock. They include out-of-pocket expenses for preparation, filing, underwriting, and issuing the stock. Such costs are part of the invested costs of the utility. They are properly reflected on the balance sheet of the utility under

³⁰³ Ex. 9 (Reed Direct) at 30.

³⁰⁴ *Id.* at 30 & Schedule 3.

³⁰⁵ *Id.* at 30.

³⁰⁶ *Id.* at 35 & Schedule 4.

³⁰⁷ *Id.* at 38-39 & Schedule 5.

³⁰⁸ *Id.* at 39-40 & Schedule 5.

“paid in capital.” They are not current expenses and thus are not reflected on the utility’s income statement. Due to the indeterminate life of an equity issuance, flotation costs should be recovered through a return adjustment, regardless of whether an issuance occurs during, or is planned for, the test year.³⁰⁹ Flotation cost adjustments are made not only to reflect current or future financing costs, but also to compensate investors for costs incurred for all past issuances comprising the total equity portion of the company’s capitalization.³¹⁰

186. The DCF and CAPM models assume no transaction costs and do not incorporate investor expectations of a return that compensates for flotation costs. As a result, it is appropriate to consider flotation costs in determining where within the range of reasonable returns a company’s authorized return should fall.³¹¹

187. Although NSP-M is an operating subsidiary of Xcel, it is appropriate to consider flotation costs because the source of capital used by NSP-M was the result of a public issuance by its parent organization, which led to the issuance costs.³¹²

188. Xcel Energy issued approximately \$345 million of stock in a public offering in September 2008.³¹³ Xcel provided evidence of the actual costs of issuance of its prior common stock.³¹⁴ It also demonstrated that it has a substantial investment plan that will require it to access the capital markets each year for the next few years.³¹⁵

189. Xcel included a flotation cost adjustment of 0.26% (26 basis points) in its recommendation. The amount was determined by modifying the DCF calculation to provide for a dividend yield that would reimburse investors for issuance costs. The proposed flotation cost adjustment recognizes the costs of issuing equity that were incurred by the former NSP because that equity is now invested in NSP-M.³¹⁶

190. After adjustment for flotation costs, Mr. Reed’s results were as follows:³¹⁷

³⁰⁹ Ex. 9 (Reed Direct) at 41-42, 44.

³¹⁰ *Id.* at 44.

³¹¹ *Id.* at 43.

³¹² *Id.* at 42-43.

³¹³ Ex. 27 (Tyson Direct) at 7.

³¹⁴ Ex. 9 (Reed Direct) at Schedule 6.

³¹⁵ Ex. 27 (Tyson Direct) at 7-8.

³¹⁶ Ex. 9 (Reed Direct) at 45-46 & Schedule 6.

³¹⁷ *Id.* at 55 (Table 4).

	Low Mean Results	Mean Results	High Mean Results
<i>Constant Growth DCF Model (flotation cost adjusted)</i>			
Constant Growth DCF – 30-day Avg. Stock Price	11.18%	12.21%	13.25%
Constant Growth DCF – 90-day Avg. Stock Price	11.17%	12.21%	13.25%
Constant Growth DCF – 180-day Avg. Stock Price	11.10%	12.14%	13.18%
<i>Capital Asset Pricing Model (including 26 basis point flotation cost adjustment)</i>			
4.31% (30-day average of the 30-year Treasury Bond Yield)	10.33%	10.55%	10.77%
4.51% (90-day average of the 30-year Treasury Bond Yield)	10.53%	10.75%	10.97%
4.48% (180-day average of the 30-year Treasury Bond Yield)	10.50%	10.72%	10.94%
4.65% - Blue Chip Forecast 30-year Treasury Bond Yield	10.67%	10.89%	11.11%
<i>Risk Premium – Moody's Baa Utility Index</i>			
30-day average as of 9/30/2008		10.92%	
90-day average as of 9/30/2008		10.87%	
180-day average as of 9/30/2008		10.78%	
Flotation Cost		0.26%	

191. In Mr. Reed's view, the mean DCF and CAPM results for the proxy group do not necessarily represent NSP-MN's cost of equity, and factors associated with the business risks faced by NSP-MN must be considered to develop a meaningful and appropriate result. The primary business risks currently facing NSP-MN are the effect of its substantial capital expenditure plan and the current volatility in the financial markets.³¹⁸

192. Since Xcel filed its last electric rate case in 2005, NSP-M has invested approximately \$2.6 billion in utility infrastructure and improvements and added approximately 40,000 new electric customers. Approximately 60-70% of the expenditures have been invested in its energy supply and nuclear generation

³¹⁸ Ex. 9 (Reed Direct) at 46-47.

business.³¹⁹ NSP-M plans to invest approximately \$3.9 billion in new investments for the period from 2008 through 2011.³²⁰ Due to current capital market conditions, NSP-M will defer some of its originally planned 2009 capital expenditures to later years, but in general expects its longer-term capital expenditures to remain consistent with the 5-year investment levels and plans discussed in its December 31, 2007, Form 10-K, which included approximately \$1.0 billion of investments in 2008 and \$805 million of specific investments in 2009. Investments in 2009 may increase beyond \$805 million for additional potential projects.³²¹ NSP-M's level of capital expenditures is related in part to Minnesota's renewable portfolio standard and the CapX 2020 transmission initiative.³²²

193. Neither Xcel Energy nor NSP-M has been precluded from accessing capital thus far. The recent severe disruptions in capital markets caused by the initial collapse in the U.S. sub-prime mortgage market, and the subsequent contraction in credit availability across the economy, however, increase the difficulty of any utility issuing new securities. The need to generate funds internally will be increasingly important because external funding costs have been driven to very high levels recently by investors who are cautious in the midst of volatile market conditions. Investors are aware of a utility's authorized ROE, and credit rating agencies and investors expect NSP-M to be able to generate a substantial portion of its investment funding from operating cash flow. Consequently, the ROE authorized by the Commission will have a direct impact on the ability of NSP-M to fund capital investment with internally generated funds.³²³

194. Mr. Reed determined that NSP-M's relative level of capital expenditures is between 1.75 and 2.50 times the projected investment levels of the proxy group companies. NSP-M faces a higher than average level of business risk compared to the companies in the proxy group due to the magnitude of its projected capital expenditures. Mr. Reed asserted that these factors suggest an ROE toward the upper end of the range of results.³²⁴

195. In Mr. Reed's view, given current market conditions and depending on the duration of such conditions, a ROE in the range of 11.00% to 12.00% represents a reasonable range of equity investors' required rate of return for investment in Xcel (although he believes that the high DCF results would support a range that has a higher upper bound than 12.00 percent). If current market conditions prevail in the longer run, Mr. Reed indicated that a ROE in the upper half of the range would be appropriate given the company's relatively higher business risk. In anticipation that current market conditions may moderate

³¹⁹ Ex. 27 (Tyson Direct) at 3.

³²⁰ *Id.* at 4.

³²¹ Ex. 27 (Tyson Direct) at 5.

³²² Ex. 9 (Reed Direct) at 51-52.

³²³ Ex. 27 (Tyson Direct) at 5-6.

³²⁴ Ex. 9 (Reed Direct) at 50, 52-53.

between the time he filed his testimony and when the Commission makes its determination, absent extenuating circumstances, Mr. Reed recommended an ROE of no less than 11.25%.³²⁵

196. Despite Mr. Reed's recommendation, Xcel limited its requested ROE to 11.00% in an effort to limit the impact of this case on its customers, and based upon optimism that the capital markets will have stabilized by the time the Commission issues its decision in this case.³²⁶

197. As a corroborating analysis, Xcel expanded the proxy group by reducing the 90% electric utility revenue and income threshold to 60%. This led to a total proxy group of 17 companies. The expanded group included the additional companies of Allete, Alliant Energy Corp., DTE Energy Co., Duke Energy Corp., and SCANA Corp. Xcel considered the results of a DCF and CAPM analysis on that group as a check on its final recommendation. The mean DCF results for the expanded proxy group, including flotation costs, are 11.60% for the 30-day and 90-day averaging period and 11.55% for the 180-day averaging period. The mean high results are 12.52% for the 30- and 90-day averaging period and 12.48% for the 180-day averaging period. Based on this analysis, Mr. Reed concluded that his recommended range of 11.00% to 12.00% is not highly dependent on the comparables group that is selected.³²⁷

198. If Mr. Reed had extended his analyses through October 10, 2008, the results of the DCF and CAPM analyses would be higher. The mean DCF and CAPM results for the 30-day averaging period for data ended October 10, 2008, are 18 basis points higher than the results based on data ended September 30, 2008. He urged that data be updated throughout this proceeding.³²⁸

2. OES Proposed ROE

199. OES recommended a ROE of 10.88% and an overall ROR of 8.83% based on use of a DCF analysis, supported by a CAPM analysis.³²⁹

200. Dr. Eilon Amit, a Public Utilities Rate Analyst for OES, used both the constant growth DCF model and the TGDCAF model in estimating the required ROE for NSP-M.³³⁰ Dr. Amit performed a DCF analysis for Xcel Energy as part of his comparison group and DCF analyses for groups of companies with investment risks similar to that of NSP-M.³³¹

³²⁵ Ex. 9 (Reed Direct) at 54.

³²⁶ Ex. 6 (Sparby Direct) at 4; Ex. 9 (Reed Direct) at 54.

³²⁷ *Id.* at 19, 55-56 & Schedule 10.

³²⁸ *Id.* at 56-57; Table 5 & Schedule 11.

³²⁹ Ex. 82 (Amit Direct) at 2, 7.

³³⁰ *Id.* at 6.

³³¹ *Id.* at 7.

201. To choose a group of companies whose investment risk is similar to NSP-M, Dr. Amit first identified an Electric Group Universe consisting of all electric utilities that are listed in the Compustat Data Base (a service provided by S&P) of November 2008 that have a primary Standard Industrial Classification code of 4911 (electric utilities), publicly traded shares on one of the stock exchanges, and had S&P bond ratings in the range of BBB-1 to A (since NSP-M's bond rating is BBB+). Thirty-four companies met these criteria.³³² Dr. Amit thereafter eliminated all foreign companies (because they operate under significantly different economic and regulatory environments and may have investment risks that are significantly different than those of NSP-M) to arrive at a Domestic Electric Group consisting of 27 companies.³³³ Before performing his DCF analysis, Dr. Amit applied additional screens to (1) eliminate companies for which the main operations do not consist of regulated retail electric services; (2) eliminate companies whose 2007 regulated revenues and regulated net incomes were less than 60 percent of total revenues and total net income respectively; (3) eliminate companies for which both beta and standard deviation deviated by more than one standard deviation from the group's mean; and (4) eliminate companies that do not pay dividends or just started to pay a dividend and did not have a reliable dividend history. The remaining 19 companies formed Dr. Amit's Initial Electric Comparison Group (IECG).³³⁴

202. Dr. Amit also chose a group of combination electric and gas utilities as a second comparison group for his DCF analysis. The initial Combination Group Universe consisted of all of the combination companies listed in the Computstat Data Base that have a primary SIC code of 4931 (combination utilities) and a S&P bond rating between BBB- to A and whose shares are publicly traded on one of the stock exchanges.³³⁵ Dr. Amit thereafter applied additional screens to eliminate companies with less than 60% regulated revenues and regulated net income, companies with no dividends, and companies for which both beta and standard deviation of price changes deviated by more than one standard deviation from the group's mean. The remaining 12 companies comprised his Initial Combination Comparison Group (ICCG).³³⁶

203. Application of the DCF analysis requires an estimate of both the expected growth rate and the expected dividend yield. Dr. Amit, like Mr. Reed, used the projected five-year growth rates provided by Zacks Investment Research and Value Line for EPS.³³⁷ Dr. Amit's best point estimate for the IECG group is 7.88% and the range of the growth rates is from a low of 6.82% to a high

³³² *Id.* at 7-8; Ex. 83, Attachments to Amit Direct at EA-2.

³³³ Ex. 82 (Amit Direct) at 8; Ex. 83 (Attachments to Amit Direct) at EA-3.

³³⁴ Ex. 82 (Amit Direct) at 8-9; Ex. 83 (Attachments to Amit Direct) at EA-4 – EA-8.

³³⁵ Ex. 82 (Amit Direct) at 9-10, 12.

³³⁶ *Id.* at 10-11; Ex. 83 (Attachments to Amit Direct) at EA-10 – EA-12.

³³⁷ Ex. 82 (Amit Direct) at 14, 18-20, 32, 53.

of 8.94%.³³⁸ His best point estimate for the ICCG is 5.98% and the range of the growth rates is from a low of 5.08% to a high of 6.88%.³³⁹

204. Because the financial markets have become extremely volatile and unpredictable since the end of September 2008, Dr. Amit agreed with Mr. Reed that it is appropriate under current economic and financial conditions to base the calculation of dividend yields on periods ending no later than September 30, 2008.³⁴⁰ Dr. Amit used the average daily closing prices for the period August-September 2008 to calculate his dividend yields for his DCF analysis for both the IECG and the ICCG.³⁴¹ Dr. Amit applied a growth-rate adjustment to reflect the fact that the companies in the comparison groups may raise their dividend rates in different quarters.³⁴² Dr. Amit determined that the average expected dividend yield for the IECG group is 4.61%, and the dividend yield ranges from a low of 4.59% to a high of 4.64%.³⁴³ The average expected dividend yield for the ICCG is 4.47%, and the dividend yield ranges from a low of 4.45% to a high of 4.49%.³⁴⁴

205. Combining the expected growth rates with the expected dividend yields results in the required ROE for the IECG ranging from a low of 11.41% to a high of 13.58%, with the best point estimate for the required ROE at 12.49%,³⁴⁵ and the corresponding required ROE for the ICCG ranging from a low of 9.53% to a high of 11.37%, with the best point estimate at 10.45%.³⁴⁶ Dr. Amit did not use these DCF results to recommend a ROE for NSP-M, however, because his initial DCF analyses resulted in required rates of return for some of the companies that deviated significantly from the average required rate of return for each group.³⁴⁷ He eliminated from his IECG and ICCG groups the companies for which the estimated required ROE from the DCF analysis deviated by more than one standard deviation from the respective average required ROE for each group.³⁴⁸

206. Eleven electric companies and nine combination companies survived this screen. Dr. Amit calls those groups the Final Electric Comparison Group (FECG) and the Final Combination Comparison Group (FCCG),

³³⁸ Ex. 82 (Amit Direct) at 18-19; Ex. 83 (Attachments to Amit Direct) at EA-13. The low expected growth rate for each company is the lower growth rate between Zacks and Value Line; the low average growth rate for the group is the average of all the companies' low expected growth rates. Similarly, the high expected growth rate for each company is the higher growth rate between Zacks and Value Line, and the high growth rate for the group is the average of all the companies' high expected growth rates. Ex. 82 (Amit Direct) at 18-19, 33.

³³⁹ *Id.* at 32; Ex. 83 (Attachments to Amit Direct) at EA-20.

³⁴⁰ Ex. 82 (Amit Direct) at 15-17, 53.

³⁴¹ *Id.* at 17, 21, 33.

³⁴² *Id.* at 21, 33.

³⁴³ *Id.* at 20-21; Ex. 83 (Attachments to Amit Direct) at EA-14.

³⁴⁴ Ex. 82 (Amit Direct) at 33-34.

³⁴⁵ *Id.* at 22.

³⁴⁶ *Id.* at 34.

³⁴⁷ *Id.* at 22, 34-35.

³⁴⁸ *Id.* at 22-23, 35.

respectively. The FECG includes Ameren Corp., American Electric Power Co., DTE Energy Co., Entergy Corp., Exelon Corp, FirstEnergy Corp., FPL Group, Inc., Great Plains Energy, Inc., Northeast Utilities, Pinnacle West Capital Corp., and Progress Energy, Inc. The FCCG includes Alliant Energy Corp., Avista Corp., Centerpoint Energy, Inc., Duke Energy Corp., Nisource, Inc., Puget Energy, Inc., SCANA Corp., Westar Energy, Inc., and Xcel Energy, Inc.³⁴⁹

207. Using the constant growth DCF method, Dr. Amit's estimated required rates of return for the FECG ranged from a low of 10.85% to a high of 12.96% with an average of 11.91%. Dr. Amit did not use those estimates to recommend a required rate of return for NSP-MN because some of the analysts' projected growth rates were not reasonable to be used as proxies for the DCF's long-term, sustainable growth rates.³⁵⁰ In particular, Dr. Amit determined that there were five companies in his FECG whose average projected growth rates for the next five years cannot be sustained in the long-run under reasonable economic and financial assumptions: Entergy Corporation, Exelon Corp., First Energy Corp., FPL Group Inc., and Northeast Utilities. The analysts' average projected growth rates for these companies are 9.70%, 9.00%, 9.50%, 9.55%, and 11.00%, respectively.³⁵¹

208. The TGDCF analysis allows two different growth rates to be used: one for the short-term growth rate and one for the long-term (sustainable) growth rate. In his TGDCF analysis, Dr. Amit used expected sustainable growth rates for those companies for the long-term, second period growth rate.³⁵² Dr. Amit's resulting TGDCF estimated required ROE for his FECG group ranged from a low of 10.08% to a high of 11.80% with an average of 10.94%.³⁵³

209. Dr. Amit's DCF analysis for the FCCG results in a required rate of return in the range of 9.31% to 10.85%, with a mean required ROE of 10.09%. These averages are based on constant growth DCF analysis for all the companies except Xcel. The rates of return on equity for Xcel are based on a TGDCF analysis. The TGDCF analysis was used for Xcel because Xcel's chairman stated in an investor meeting in New York on December 3, 2008, that the Company's goal is to achieve an annual sustainable EPS growth rate in the range of 5% to 7%. Dr. Amit used the average of this range (6%) for Xcel's sustainable long-term growth rate.³⁵⁴

210. Dr. Amit conducted a CAPM analysis as a check on the reasonableness of his DCF and TGDCF analyses.³⁵⁵ Due to the recent unusual volatility of the yields for 5-Year Treasury Bonds, Dr. Amit based his analysis on

³⁴⁹ Ex. 82 (Amit Direct) at 23-24, 35; Ex. 83 (Attachments to Amit Direct) at EA-16, EA-23.

³⁵⁰ Ex. 82 (Amit Direct) at 23-25.

³⁵¹ *Id.* at 27-31.

³⁵² *Id.* at 26-27.

³⁵³ *Id.* at 31; Ex. 83 (Attachments to Amit Direct) at EA-19.

³⁵⁴ Ex. 82 (Amit Direct) at 35-36; Ex. 83 (Attachments to Amit Direct) at EA-26.

³⁵⁵ Ex. 82 (Amit Direct). at 36, 44.

the average yields on 20-Year Treasury Bonds over the period of August 2008 through September 2008, which is 4.43%. Because the 20-Year Treasury Bill is not a free-risk asset and incorporates a risk-premium associated with interest risk, using it in a CAPM analysis may result in an upward bias of the ROE.³⁵⁶ Dr. Amit used historical data from 1926-2007 to estimate the risk premium. During that period, the average arithmetic mean of total return for the Large Company Stocks (the S&P 500 Composite) was 12.3%, and the average total return on Long-Term Government Treasury bills was 5.80%. Based on these averages, the risk premium is 6.50%. Dr. Amit used the betas listed in the Value Line Investment survey of September-November 2008 for his CAPM analysis. The average beta for both FECG and FCCG is 0.78.³⁵⁷ Based on the riskless asset rate, the risk premium, and the betas, Dr. Amit's CAPM estimated rates of return are 9.51% for both FECG and FCCG.³⁵⁸

211. Dr. Amit also proposed an adjustment for flotation costs and agreed that this adjustment is appropriate even if no new issuances are planned in the near future. To arrive at the adjustment, he divided the expected dividend yield by 1-F, where F is the percentage of issuance costs. For the value of F, Dr. Amit used the average flotation cost of 5.624% proposed by Mr. Reed. Other studies also indicate average flotation costs of around 5%.³⁵⁹ For both the FECG and the FCCG, the flotation cost adjustment for the mean ROE is 28 basis points, which were also added to the CAPM ROE. Dr. Amit's rate of return estimates for FECG and FCCG including his adjustment for flotation costs are as follows:

	DCF/TGDCF			
	<u>Low</u>	<u>Average</u>	<u>High</u>	<u>CAPM</u>
FECG	10.36%	11.22%	12.08%	9.79%
FCCG	9.59%	10.37%	11.13%	9.79%

Based on Dr. Amit's DCF and TGDCF analyses for the FECG and FCCG groups, the required ROE for NSP-MN ranges from a low of 9.59% to a high of 12.08%. All of the CAPM ROE estimates are lower than the average DCF/TGDCF ROEs for FECG and FCCG, respectively.³⁶⁰

212. Because this proceeding addresses the required rate of return for the electric operations of NSP-M, Dr. Amit acknowledged that the most significant weight must be assigned to the DCF/TGDCF analysis for the FECG group. The DCF results for the FCCG group, however, also provide additional important information. Accordingly, he assigned a weight of 60% to the FECG group and 40% to the FCCG group. Based on these weights, Dr. Amit concluded

³⁵⁶ *Id.* at 37-39, 55-56; Ex. 83 (Attachments to Amit Direct) at EA-33.

³⁵⁷ Ex. 82 (Amit Direct) at 40; Ex. 83 (Attachments to Amit Direct) at EA-16 and EA-23.

³⁵⁸ Ex. 82 (Amit Direct) at 41; Ex. 83 (Attachments to Amit Direct) at EA-29 and EA-35.

³⁵⁹ Ex. 82 (Amit Direct) at 42, 43; Ex. 83 (Attachments to Amit Direct) at EA-39.

³⁶⁰ Ex. 82 (Amit Direct) at 43 and Table 8.

that the ROE for NSP-M ranges from a low of 10.06% to a high of 11.90%. Using the same weights for the mean ROEs of FECG and FCCG, Dr. Amit's required recommended ROE for NSP-M is 10.88%.³⁶¹

213. Dr. Amit recommended a ROE of 10.88% and an overall ROR of 8.83%, as summarized below:³⁶²

Component	Capitalization Ratio (%)	Cost (%)	Weighted Cost (%)
Long-Term Debt	46.25	6.61	3.06
Short-Term Debt	1.28	4.41	0.06
Common Equity	<u>52.47</u>	<u>10.88</u>	<u>5.71</u>
Total	100.00%		8.83%

3. Further Analysis of Proposed ROEs by OES and Xcel

214. Mr. Reed concluded that both Dr. Amit's recommended 10.88% ROE and the 11.00% ROE requested by Xcel are reasonable. In Mr. Reed's view, Dr. Amit's recommended 10.88% ROE is at the bottom of the range of reasonable returns.³⁶³

215. Dr. Amit expressed concern about or disagreed with the following aspects of Mr. Reed's DCF analysis:

a. According to Dr. Amit, Mr. Reed's inclusion of 90 and 180 days prices to calculate his dividend yields may be inappropriate. As a practical matter, however, Dr. Amit noted that Mr. Reed's 90 and 180 days average dividend yields are very close to his 30 days average dividend yield and did not seem to bias his DCF analyses.³⁶⁴

b. Dr. Amit proposed to exclude CNL, EDE, IDA, and WR from Mr. Reed's DCF analysis because their ROE deviated from the mean ROE by more than one standard deviation. As a result of this screen, the ROEs for Mr. Reed's group are 11.82%, 11.76%, and 11.69% for the 30, 90, and 120 days DCF analyses, respectively.³⁶⁵

c. Dr. Amit proposed to substitute TGDCF analysis for three companies in Mr. Reed's comparison groups (Entergy, FPL Group, and Northeast Utilities) because they may have five-year projected growth rates that are not sustainable. For these companies, Dr. Amit substituted his TGDCF's estimated ROEs for Mr. Reed's DCF estimated ROE. As a result, the modified

³⁶¹ Ex. 82 (Amit Direct) at 43-45.

³⁶² *Id.* at 51.

³⁶³ Ex. 10 (Reed Rebuttal) at 1-2, 5.

³⁶⁴ *Id.* at 53.

³⁶⁵ *Id.* at 54; Ex. 83 (Attachments to Amit Direct) at EA-36.

DCF analyses of Mr. Reed's group result in average ROEs of 11.04%, 11.04%, and 10.98% for the 30, 90, and 180 day DCF analyses, respectively (including the adjustment for flotation costs).³⁶⁶

216. Dr. Amit raised concerns about two aspects of Mr. Reed's CAPM analysis:

a. Dr. Amit disagreed with Mr. Reed's choice of the risk premium. Mr. Reed used the difference between the arithmetic average return on the large stock companies and the arithmetic average income return on long-term government bond over the period 1926-2007 and arrived at a risk premium of 7.10%. Dr. Amit disagreed because the risk premium is the difference between the total return on two assets, not the difference between one asset's total return and the other asset's income return only. Using the same assets as Mr. Reed, Dr. Amit concluded that the appropriate risk premium is 6.5%.³⁶⁷ Substituting the risk premium of 6.5% for the 7.1% used by Mr. Reed, the CAPM results (including flotation cost adjustments) are as follows:

Period	Projected	30-days	90-days	180-days
Returns:	10.46%	10.03%	9.95%	10.28%

The average of these estimates is 10.18%.³⁶⁸

b. While Dr. Amit acknowledged that the choice of 30-Year Treasury Bond yield as a proxy for the risk-free yield may be reasonable, he cautioned that it includes an interest rate premium and therefore may bias the CAPM estimated ROE upward.³⁶⁹

217. Dr. Amit also disagreed with the methodology used by Mr. Reed in his Risk Premium analysis, arguing that Mr. Reed's use of an econometric model to estimate the risk premium is inconsistent with his use of an historical risk premium to calculate his CAPM's ROE. Dr. Amit reasoned that the underlying assumption in using historical data to calculate the risk premium is that risk premiums are not sensitive to changes in the financial markets and thus do not change as a result of changes in interest rates or changes in the yields on long-term utilities' bonds. In contrast, estimating the risk premium using an econometric model is based on the assumption that risk premiums are sensitive to changes in the yields on long-term utility bonds. As a result, Dr. Amit contends that Mr. Reed's risk premium analysis is inconsistent with his CAPM analysis.³⁷⁰

³⁶⁶ Ex. 82 (Amit Direct) at 54-55; Ex. 83 (Attachments to Amit Direct) at EA-36.

³⁶⁷ Ex. 82 (Amit Direct) at 56.

³⁶⁸ *Id.* at 56-57.

³⁶⁹ *Id.* at 55-56.

³⁷⁰ *Id.* at 58.

218. Dr. Amit modified Mr. Reed's estimated rates of return as follows:³⁷¹

<u>Method of Estimation</u>	<u>Average ROE</u>
DCF	11.02%
CAPM	10.18%
Risk Premium	10.93%
Grand Average	10.71%

219. Regarding the expected growth rates used in their DCF analyses, Dr. Amit and Mr. Reed agree that, as a matter of principle, the timing of the dividend yields (stock prices) used in a DCF analysis should correspond to the timing of the projected growth rates used in a DCF analysis.³⁷² Dr. Amit does not necessarily agree, however, with Mr. Reed's argument that it would have been more appropriate for Dr. Amit to use the Zacks' and Value Line projected growth rates available on September 30, 2008, for his DCF analyses instead of the growth rate Dr. Amit in fact used (December 19, 2008, for Zacks' growth rates and September, November 2008 for Value Line growth rates). Dr. Amit contended that, when using the average stock prices over a fairly long time period (60 days in Dr. Amit's analysis and 90 or 180 days in Mr. Reed's analyses), these average prices may not appropriately reflect the projected growth rates at the end of each period (September 30, 2008). Therefore, Dr. Amit argues that substituting the projected growth rates of September 30, 2008, for his growth rates does not resolve the timing issue but instead creates a different mismatch between the timing of projected growth rates and the timing of the stock prices.³⁷³

220. Mr. Reed replicated Dr. Amit's DCF analysis and changed only the period of the analysts' earnings growth projections to those in effect as of September 30, 2008. The result was a weighted mean ROE of 10.94 percent, an increase of 6 basis points from Dr. Amit's 10.88% weighted mean ROE. Mr. Reed concluded that these results show that Dr. Amit's use of growth rate projections from slightly different time periods did not have a significant effect.³⁷⁴ Dr. Amit agrees with Mr. Reed that substituting the September 30, 2008, projected growth rates for Dr. Amit's projected growth rates has an insignificant impact on the DCF results.³⁷⁵

4. Review of Updated Information

221. The OES did not propose to update its ROE recommendation due to the extreme volatility of the financial market starting with the end of September

³⁷¹ *Id.* at 58 and Table 10.

³⁷² *Id.* at 58.

³⁷³ *Id.* at 7-8.

³⁷⁴ *Id.* at 7.

³⁷⁵ *Id.* at 7-8.

2008 and continuing through May 6, 2009. Because of this unusual volatility, it would not be appropriate to use the most recently available data to estimate the required ROE for NSP-M. Dr. Amit continues to recommend a ROE of 10.88% and an overall ROR of 8.83%.³⁷⁶

222. Mr. Reed updated Dr. Amit's DCF analysis using market data ending April 24, 2009, to determine whether current market data would have any adverse effect on the conclusions drawn by Dr. Amit and himself regarding the impact of the current market volatility. Because Puget Energy Inc., merged into Puget Holdings LLC in February of 2009 and is no longer publicly traded, Mr. Reed excluded Puget Energy from his updated analysis of Dr. Amit's FCCG proxy group. Mr. Reed was otherwise able to replicate Dr. Amit's TGDCF analysis. Mr. Reed concluded that there has not been any reduction in the required ROE as result of recent capital market conditions.³⁷⁷ Dr. Amit agreed with Mr. Reed's conclusion.³⁷⁸

223. To verify that current market conditions do not warrant a change in his original ROE recommendation, Dr. Amit also performed his own updated DCF analysis using the average closing prices over the period April 5 through May 5, 2009, the most recent available growth rates for Value Line (March, May 2009) and Zacks (May 7, 2009), and the most recently available annual dividend rates. Dr. Amit's updated DCF results are similar to Mr. Reed's updated DCF results. He concluded that, while current market conditions have not changed to justify a lower required ROE than he recommended in his Direct Testimony, the market volatility remains unusually high and, therefore, a DCF analysis based on current market conditions may not be used for rate of return recommendations.³⁷⁹

224. The results of Mr. Reed's and Dr. Amit's review of updated data, which include flotation cost adjustments, are as follows.³⁸⁰

	Low	Mean	High
Reed Update of Amit DCF/TGDCF (Weighted Average 60% FECCG/40% FCCG)	11.26%	12.06%	12.86%
Amit Updated DCF/TGDCF (Weighted Average 60% FECCG/40% FCCG)	11.08%	12.00%	12.93%

³⁷⁶ Ex. 84 (Amit Surrebuttal) at 1-3.

³⁷⁷ Ex. 10 (Reed Rebuttal) at 7-8.

³⁷⁸ Ex. 84 (Amit Surrebuttal) at 4-5.

³⁷⁹ *Id.* at 5-6.

³⁸⁰ Ex. 10 (Reed Rebuttal) at 8; Ex. 84 (Amit Surrebuttal) at 6.

5. ALJ Recommendation

225. The Administrative Law Judge recommends that the Commission use the ROE recommended by the OES (10.88%), which produces a ROR of 8.83%.

226. OES's decision to select two groups of publicly-traded utilities, one comprised of electric companies and one of combination electric and gas companies, and the screening criteria it applied to those groups were reasonable to ensure that the companies that were used in its analysis have investment risk similar to that of NSP-M. The OES properly eliminated from both groups companies for which the estimated required ROE deviated by more than one standard deviation from the respective average required ROE for each group. The OES also appropriately recognized that some companies in the comparison groups have projected short-term growth rates that cannot be sustained in the long run and used the TGDCF model rather than the constant growth DCF model to estimate the required ROE for those companies. OES properly assigned a greater weight to the ROE results of the FECG group (60%) because that group contained electric utilities, but recognized that important information could also be obtained from the FCCG group, which was assigned a lesser weight (40%). Dr. Amit provided detailed support for each step of his analysis, his selection of reasonable projected growth rates and dividend yields, and his use of the CAPM as a check on reasonableness. Xcel's argument that Dr. Amit should have used projected growth rates available on September 30, 2008, for his DCF analyses rather than the ones he in fact used is not persuasive.

227. OES demonstrated a number of flaws in Mr. Reed's DCF, CAPM and Risk Premium analyses and established that, if these flaws were corrected, the grand average ROE is 10.71%. Xcel has failed to substantiate the reasonableness of its recommendation of a higher ROE.

228. It is appropriate to allow recovery of flotation costs in this matter as part of the required return, as calculated by the OES. There is ample support in the record for granting the flotation adjustment. Xcel provided evidence of the actual costs of issuance of its prior common stock and demonstrated that it has a substantial investment plan that will require it to access the capital markets each year for the next few years. Xcel Energy issued approximately \$345 million of stock in a public offering in September 2008. OES provided a detailed explanation of its calculation of the flotation adjustment, and its recommended adjustment was very close to that recommended by Xcel. Moreover, in its 2008 Order in the Otter Tail Power case,³⁸¹ the Commission approved the OES's proposal to include a flotation adjustment based on findings that Otter Tail had identified impending needs for increased capital, flotation costs were an appropriate cost of raising capital, and the PUC had previously authorized recovery of flotation costs even when a utility had not sold any stock during the

³⁸¹ See *Otter Tail Power Order* at 37.

rate case test year.³⁸² The Commission also authorized recovery of flotation costs in the 2008 Minnesota Power Rate Case.³⁸³

229. Accordingly, the Administrative Law Judge recommends that the Commission impute the following capital structure to NSP-M for ratemaking purposes:

<u>Capitalization</u> <u>Cost</u>	<u>Percentage of</u> <u>Total Capitalization</u>	<u>Cost</u>	<u>Weighted</u>
Long-term Debt	46.25%	6.61%	3.06%
Short-term Debt	1.28%	4.41%	0.06%
<u>Common Equity</u>	<u>52.47%</u>	10.88%	<u>5.71%</u>
Total	100.00%		8.83%

VI. RATE DESIGN

230. Rate design, in contrast to the determination of the revenue requirement, is largely a quasi-legislative function. It involves establishment of the utility's rate structure, such as deciding in what proportions the revenue requirement will be recovered from each customer class. This step of rate making largely involves policy decisions to be made by the Commission.³⁸⁴

231. The Commission has historically considered a variety of cost and non-cost factors when designing rates. In addition to the results of a class cost of service study (CCOSS), which is required in all rate cases,³⁸⁵ the Commission considers other factors, including economic efficiency; continuity with prior rates; ease of understanding; ease of administration; promotion of conservation; ability to pay; and ability to bear, deflect, or otherwise compensate for additional costs.³⁸⁶

232. Nearly all of the contested rate design issues in this case involve questions of which customer classes, or rate groups within classes, should be assigned revenue responsibility. These disputes include issues related to the methodology of the CCOSS, use of the E8760 allocator, the allocation of the revenue requirement to the customer classes, the amount of the interruptible discounts, the allocation of wind generation fixed costs between capacity and

³⁸² *Id.* at 57-58.

³⁸³ *In the Matter of the Application of Minnesota Power for Authority to Increase Electric Service Rates in Minnesota*, Docket No. E-015/GR-08-415, Findings of Fact, Conclusions of Law and Order at 37 (May 4, 2009).

³⁸⁴ See *St. Paul Area Chamber of Commerce v. Minnesota Public Service Commission*, 312 Minn. 250, 260, 251 N.W.2d 350, 357 (1977).

³⁸⁵ Minn. R. 7825.4300 C (2007).

³⁸⁶ See *St. Paul Area Chamber of Commerce*, 312 Minn. at 260, 251 N.W.2d at 357; *In the Matter of the Application of Minnesota Power for Authority to Increase Electric Service Rates in Minnesota*, Docket No. E015/GR-08-415, Findings of Fact, Conclusions of Law, and Order at 63 (May 4, 2009).

energy, rate rider design, and the Commercial & Industrial (C&I) demand and energy charges.

A. Class Cost of Service Study

233. The purpose of a CCOSS is to identify, as accurately as possible, the responsibility of each customer class for each cost incurred by the utility in providing service. The CCOSS can then be used as one important factor in determining how costs should be recovered from customer classes through rate design.³⁸⁷

234. Xcel filed an embedded CCOSS that uses essentially the same methodology accepted in Xcel's rate cases since 1992.³⁸⁸ Based on the CCOSS, as adjusted to reflect interruptible rate discounts, rates set to recover Xcel's proposed deficiency would have to increase as follows to achieve equal rates of return from each class: Residential, 10.4%; C&I Non-Demand, 0%; C&I Demand, 3.9%; and Street Lighting, -4.9%.³⁸⁹

235. Xcel's method, which it calls a "stratification" method, is a company-specific method that is similar to the "equivalent peaker" method described in the manual developed by the National Association of Regulatory Commissioners.³⁹⁰ The Commission recently approved use of this method by Otter Tail Power.³⁹¹

236. Equivalent peaker methods are based on generation expansion planning practices, which consider peak demand loads and energy loads separately in determining the need for additional generating capacity and the most cost-effective type of capacity to be added. These methods generally result in significant percentages (40 to 75 percent) of total production plant costs being classified as energy-related, with the results that energy unit costs are relatively high and the revenue responsibility of high load factor classes and customers is significantly greater than indicated by a demand methodology that assigns cost based on "peak responsibility" methods. The premise of the equivalent peaker method is that (1) increases in peak demand require the addition of peaking capacity only; and (2) utilities incur the costs of more expensive intermediate and baseload units because of the additional energy loads they must serve. Thus, the cost of peaking capacity can properly be regarded as peak demand-related and classified as demand-related in the cost of service study. The difference between the utility's total cost for production plant and the cost of peaking capacity is caused by the energy loads to be served by the utility and is classified as energy-related in the cost of service study.³⁹²

³⁸⁷ Ex. 77 (Ouanes Direct) at 5.

³⁸⁸ Ex. 2 (Work Papers, Vol. 3). A summary of the results is contained in Ex. 36 (Zins Direct) at 5.

³⁸⁹ Ex. 36 (Zins Direct) at 5.

³⁹⁰ Ex. 78 (Oanes Rebuttal) at 9; Ex. 55.

³⁹¹ See *Otter Tail Power Order* at 69-70.

³⁹² Ex. 55 at 52-53.

237. In the Otter Tail Power rate case, the Commission explained the theory behind the equivalent peaker methodology as follows:

Electric utilities incur both fixed and variable costs. The costs of building a generator are generally fixed; they do not change in proportion to the amount of energy generated. In contrast, many operating costs are variable; they change depending on how much the plant is operated. Because a utility must build its plant with sufficient capacity to supply the electricity required by customers even on days of peak demand, fixed plant costs are typically regarded as demand-related costs. In contrast, energy-related costs—such as the cost of fuel or electricity purchased from other generators—are typically variable.

But not all energy-related costs are variable. For example, a utility may install a generator that is expensive to build but uses inexpensive fuel (typical of a “baseload” generator). In this case, the choice to incur extra building costs may be understood as a substitute for incurring extra fuel costs.

Whether to characterize costs as related to energy or demand influences class allocations because a utility incurs a different level of demand- and energy-related costs for each customer class. The choice to characterize fixed cost as energy-related benefits the Residential class, which tends to have a low load factor, or ratio of average usage to peak usage. The choice to characterize fixed costs as demand-related benefits the high load factor customers.

The CCOSS determines how [the utility’s] production plant investment (fixed) costs and related operating expenses are assigned to various classes of ratepayers. Different methodologies assign production plant costs based on class energy usage and peak demand usage. The selection of methodology is critical to a determination of what portion of fixed production costs is to be attributed to meeting demand and allocated to the capacity/demand component of rates and what portion attributed to providing energy and allocated to the energy component of rates.

...

Otter Tail used an equivalent peaker methodology to determine the portion of production plant costs to treat as demand versus energy costs. The Company asserted that its equivalent peaker methodology was approved for use in the Company’s 1986 rate case, as well as in Xcel Energy’s previous seven rate cases. The equivalent peaker method reflects the fact that baseload plants, rather than peakers, are built when there is sufficient need for

energy to justify the higher capital costs of a baseload plant. As a result, the portion of baseload fixed cost that exceeds the fixed cost of a peaking plant should be allocated on the basis of energy and not demand.³⁹³

238. In a nutshell, the method Xcel uses to stratify production plant investment compares the average insurance replacement cost per MW of capacity of the various sources of capacity, including nuclear, steam fossil hydro, and gas turbine or diesel generation. The replacement cost is obtained by applying construction cost escalators to actual booked costs of existing plants. The least expensive plant source (gas turbine or diesel peaking generation) is compared to the other sources. The percentage amount that peaking represents of other capacity sources is used to determine the peaking (demand) component of each capacity source, with the remainder allocated to energy. The stratification method classifies production plant investment into capacity as follows: gas turbine and diesels, 100%; steam fossil, 32.7%; hydro, 28%; and nuclear, 18.6%.³⁹⁴ Purchased power is separated into capacity (55%) and energy (45%) based on actual test year purchased capacity costs.³⁹⁵ Xcel then allocates 75.5% of the capacity portion of plant cost to the summer months and 24% to the winter months, to reflect the use of combustion turbines to meet both summer and winter peak demand.³⁹⁶ Energy costs are allocated using the E8760 allocator, which uses combined forecasts of hourly marginal energy costs and class loads to represent class cost responsibilities.³⁹⁷ Using the stratification methodology, approximately 35% of Xcel's fixed plant costs are treated as capacity (demand) and 65% are treated as energy.³⁹⁸

239. The OES reviewed the proposed CCOSS, found it to be reasonable, and recommends that the Commission adopt it.³⁹⁹ The XLI, MCC, Commercial Group, and OAG objected to various aspects of Xcel's CCOSS.

1. Allocation of Interruptible Credits in the CCOSS

240. Xcel treats Interruptible credits as the cost of purchased capacity, and it allocates those costs to all customer classes based on total demand. It views interruptible service as firm service, which Xcel has the option to buy back from willing customers through the Interruptible discount. Xcel accordingly views

³⁹³ *Otter Tail Power Order* at 68-69.

³⁹⁴ Ex. 2 (Vol. 3, Guide to Embedded Electric CCOSS) at 10. The stratification method splits production plant investment into capacity as follows: gas turbine and diesels, 100%; steam fossil, 32.7%; hydro, 28%; and nuclear, 18.6%. *Id.*

³⁹⁵ Ex. 38 (Zins Rebuttal) at 10-11.

³⁹⁶ Ex. 38 (Zins Rebuttal) at 12-13; Tr. 1:145 (Engelking).

³⁹⁷ Ex. 41 (Huso Rebuttal) at 8.

³⁹⁸ Ex. 38 (Zins Rebuttal) at 10-11.

³⁹⁹ Ex. 77 (Ouanes Direct) at 9.

Interruptible rate discounts as power supply costs that need to be recognized by all customers in the CCOSS.⁴⁰⁰

241. XLI contends the cost of Interruptible credits should not be allocated in the CCOSS to Interruptible customers. It maintains that Interruptible customers do not cause these costs, and they should not be charged with responsibility for them in the CCOSS.⁴⁰¹

242. The OES recommends that the Commission approve Xcel's treatment of Interruptible Service costs.⁴⁰²

243. Interruptible customers contribute to lower system costs, because their service is available for interruption on the system if needed. They receive a discount for permitting their service to be interrupted. As a result, the capacity of the system can be smaller because it is not necessary to design the system to serve Interruptible customers at peak periods. These lower system costs benefit all customers.⁴⁰³

244. The Administrative Law Judge recommends that the Commission approve Xcel's allocation of Interruptible credits in the CCOSS.

2. *Proposed Modifications to the CCOSS*

245. The XLI, the MCC, and the Commercial Group all propose modifications to this methodology that shift revenue requirements away from C&I Demand customers to Residential and C&I Non-Demand customers. These modifications are based on a premise that fundamentally differs from that underlying the stratification methodology: that all production plant is used to meet capacity, and energy is simply a by-product of capacity.

246. The XLI proposed modifications to the CCOSS that differ from Xcel's method in three main ways. First, the XLI would estimate capacity investment based on the midpoint between the avoided cost of a conventional combustion turbine and Xcel's replacement cost (which the XLI has determined to be \$592 per kW, as opposed to the replacement cost of \$502 per kW used by Xcel). Using a similar process, the XLI would separate the cost of purchased power contracts into capacity and baseload (energy). The XLI maintains it is not necessary to translate capacity costs for other plant types in the same manner for purposes of comparison, because the combustion turbine cost is forward-looking.⁴⁰⁴ Using this approach, the XLI classifies 66% of total production plant (including nuclear fuel) to capacity. If nuclear fuel were allocated directly to energy, the capacity percentage would increase to approximately 90%.

⁴⁰⁰ Ex. 36 (Zins Direct) at 6-7.

⁴⁰¹ Ex. 112 (Pollock Direct) at 14, 29-31; Ex. 114 (Pollock Surrebuttal) at 22.

⁴⁰² Ex. 78 (Ouanes Rebuttal) at 5-13.

⁴⁰³ *Id.* at 4.

⁴⁰⁴ Ex. 112 (Pollock Direct) at 23-26 & Schedules 4-5; Tr. 4:24-25, 44.

247. Second, the XLI would not use a weighted average of summer and winter coincident peaks to allocate capacity costs; it would allocate capacity to loads during the hours when the state load is at or above 90% of the single annual system peak load.⁴⁰⁵ The XLI maintains this is appropriate because only summer peak demand determines Xcel's capacity requirement, and once Xcel has installed sufficient capacity to meet summer peak demand, that capacity is available year round to meet demands on the system.⁴⁰⁶ This results in the fixed cost of production plant being allocated to loads occurring during 32 hours of June, July, and August. The underlying assumption is that peak capacity is not needed except for these 32 hours per year. Because the residential class uses a comparatively high load during these peak hours, the result is to shift a large portion of cost to the residential class.⁴⁰⁷

248. Third, the XLI would not use the E8760 allocator but would allocate all baseload (energy) costs to the first 1,000 hours of the load duration curve. This is known as a "break-even" methodology, on the basis that this is the number of operating hours in which the total cost of base/intermediate and peaking capacity is the same.⁴⁰⁸ Under this theory, the remaining 7,760 hours in the year are considered irrelevant to the decision to build baseload plant. This change has the effect of allocating energy costs during 11.4% of the available annual hours when usage is the highest, with the result that additional costs are shifted to the Residential class.⁴⁰⁹

249. The XLI's approach would result in shifting approximately \$20 million from the C&I Demand class to the Residential class.⁴¹⁰ The XLI notes that these results are similar to those obtained using the Average and Excess Demand method, which is used by NSP-M affiliates PSCo and SPS in their respective jurisdictions.⁴¹¹ PSCo and SPS use that method, however, because the state commissions in those jurisdictions require it.⁴¹²

250. The MCC initially advocated using the new cost of a combustion turbine as opposed to the replacement cost used by Xcel; the MCC withdrew this position during the hearing, because it agreed with Xcel that the cost comparisons should be made using a similar cost methodology for all plant.⁴¹³ The MCC and the Commercial Group would allocate 100% of fixed generation costs to capacity and would allocate capacity costs to customer classes on the basis of class contribution to system peak demand.⁴¹⁴ These parties argue that

⁴⁰⁵ Ex. 112 (Pollock Direct) at 20-23, 27.

⁴⁰⁶ Ex. 114 (Pollock Surrebuttal) at 20.

⁴⁰⁷ Ex. 38 (Zins Rebuttal) at 12.

⁴⁰⁸ Ex. 112 (Pollock Direct) at 16-20, 27.

⁴⁰⁹ Ex. 38 (Zins Rebuttal) at 14.

⁴¹⁰ Tr. 4:16 (Pollock).

⁴¹¹ Ex. 112 (Pollock Direct) at 35-37.

⁴¹² Tr. 2A:44 (Zins).

⁴¹³ Tr. 3:13 (Schedin).

⁴¹⁴ Ex. 61 (Schedin Direct) at 10-11; Ex. 50 (Baudino Direct) at 6.

this is appropriate because all system planning by NSP-M is based on the need to meet capacity requirements, not energy requirements.⁴¹⁵

251. The OAG also objects to the E8760 allocator, but it does not offer an alternative method of allocating energy costs. The OAG also contends that all CCROSS studies, regardless of the method used, are arbitrary and result-oriented.⁴¹⁶ The OAG argues that because the reliability of CCROSS analyses is limited, the results should not be used to guide revenue allocation decisions.

252. With regard to Xcel's method of using replacement cost to stratify all plant types, the ALJ concludes that this method is reasonable. It is not reasonable to compare the cost of a combustion turbine calculated one way with other plant costs calculated a different way. The use of an avoided cost number as proposed by the XLI should be rejected.

253. With regard to Xcel's use of the E8760 allocator for allocation of energy costs, the Administrative Law Judge concludes that Xcel's method is appropriate. The Commission approved use of the E8760 allocator in Xcel's last rate case (Docket No. E-002/GR-05-1428), in the Minnesota Power rate case (Docket No. E-015/GR-08-415), and it has required Otter Tail Power to use the same allocator in its next rate case.⁴¹⁷ The ALJ recommends that the Commission approve it here.

254. With regard to Xcel's method of classifying fixed generation costs into capacity and energy, the Administrative Law Judge concludes that Xcel's stratification method appropriately reflects the reasonable assumption that the objective of generation resource planning is to plan, build, and economically operate over time an optimum mix of generation plant types and purchased power, in order to minimize total system costs over the life of the plants and the planning horizon.⁴¹⁸ Capacity to meet peak load is not the only driver of fixed generation investment; rather, it is the need for year-round energy that justifies the high capital costs of baseload plants, whereas the low capital costs of combustion turbines justify the high energy costs needed to serve short peak loads. Xcel's method appropriately assumes that capacity is needed in both summer and winter, not just during the 32 hours of single annual system peak load, and that the energy needs during hours outside the break-even point are critical in deciding how much baseload plant should be built.⁴¹⁹

255. As the parties point out, there are many possible methods for classifying costs. The Commission has made the policy decision that use of the stratification method is appropriate for Xcel. The Commission has consistently required Xcel's use of this method since 1977. The modifications proposed by

⁴¹⁵ Tr. 3:44.

⁴¹⁶ Ex. 66 (Lindell Direct) at 41.

⁴¹⁷ *Otter Tail Power Order* at 79.

⁴¹⁸ Ex. 38 (Zins Rebuttal) at 15.

⁴¹⁹ Ex. 38 (Zins Rebuttal) at 15.

XLI and MCC produce extreme results and are skewed in favor of the C&I Demand class. As a factual matter, the ALJ does not believe that these changes are required in order to properly analyze cost responsibility of customer classes. As a policy matter, the XLI and MCC have not convinced the Administrative Law Judge that Xcel's method should be revised in order to shift more costs to the Residential class. The Administrative Law Judge accordingly recommends that the Commission adopt Xcel's CCOSS as the starting point in designing rates.

B. Classification of Grand Meadow Project Costs in the CCOSS

256. If the Commission accepts the recommendation to move Grand Meadow costs into base rates, the Commission will need to address how that project will impact the CCOSS. Using Xcel's stratification methodology, 4.7% of project costs are allocated to capacity, while 95.3% are allocated to energy.⁴²⁰ Xcel maintains this allocation properly reflects the characteristics of wind generation. Wind is not a significant source of capacity, because the wind blows the least during the hot and humid days of the summer peak demand. Like intermediate and baseload plant, the cost of wind generation is justified in large part by the low cost of the energy it produces.⁴²¹ Xcel maintains the functional classification of Grand Meadow is accurately accounted for in the CCOSS.

257. The Commercial Group agrees that wind generation should be allocated in accordance with Xcel's CCOSS.⁴²²

258. The OES maintains that wind energy is acquired because of its renewable characteristics and to help satisfy RES statutory requirements. It advocates that 20% of Grand Meadow project costs should be treated as capacity in the CCOSS, because that is the capacity factor credited by MISO in the absence of actual experience. The OES position would require that when the capacity factor is increased to 39%, as anticipated, the allocation of costs in the CCOSS would have to be revised. The XLI characterizes this aspect of the OES approach as "unstable and unwieldy."⁴²³

259. Although it maintains the stratification method is not appropriate for wind because the method does not consider renewable characteristics, OES does not know whether MISO's capacity accreditation takes these characteristics into account either.⁴²⁴ The OES does not maintain that its recommended capacity classification bears any relationship to capacity cost; it acknowledges that this is a policy argument that is expressly directed at influencing which classes of customers will absorb the responsibility for these costs.⁴²⁵

⁴²⁰ Ex. 37 (Zins Supplemental Direct) at 5.

⁴²¹ Ex. 38 (Zins Rebuttal) at 25-26; Tr. 1:120 (Engelking).

⁴²² Ex. 50 (Baudino Direct) at 9.

⁴²³ Ex. 113 (Pollock Rebuttal) at 5.

⁴²⁴ Tr. 3:163 (Peirce).

⁴²⁵ Tr. 3:157 (Peirce).

260. In response, Xcel argues that the purpose for accelerated development of wind energy is to obtain the environmental benefits of this source of energy (not capacity), as compared to other energy sources.⁴²⁶ Wind energy is intermittent and available only when the wind blows, which is further evidence that its function is to provide energy, not capacity.

261. Because wind energy is intermittent, it is necessary to pair it up with additional ancillary services and other generation system integration costs associated with wind energy, in order to efficiently combine it with the rest of the system's energy resources. The XLI argues that these costs from wind-following generation should also be treated as capacity costs and allocated with wind costs as a system resource, based on the average of all other resources. Based on this method, 66% of Grand Meadow costs would be treated as capacity.⁴²⁷

262. In response, Xcel points out that the additional wind-integration costs do not change the fact that wind energy is energy (not capacity); they simply add to the total cost of the energy.⁴²⁸

263. The MCC advocates treating wind as a system resource, using the system average split between capacity and energy (35%/65%).⁴²⁹ Xcel maintains there is no basis in the record for treating wind generation as having capacity characteristics similar to a baseload coal plant.⁴³⁰

264. CCOSS methodologies are designed with the basic assumption that generation assets are added to a system based on a capacity need, an energy need, or a combination of the two. The OES, XLI, and MCC point to the statutory mandates requiring use of renewable energy as the reason for deviating from the results of Xcel's stratification method, arguing that wind does not fit into the generation-planning framework in the same way that traditional energy sources do. But Xcel argues that wind fits into the framework like any other generation source and that, to be reasonable and economically defensible, the CCOSS must treat each generation type in the same manner.⁴³¹

265. The Administrative Law Judge agrees with Xcel that the fact that Grand Meadow helps satisfy RES requirements does not make it more capacity-related, and there is no economic reason to assign it a 20% capacity value in the CCOSS.⁴³² The CCOSS does not allocate the cost of any other generation source between capacity and energy based on characteristics such as reliability, renewability, environmental cost, or statutory mandate. The Commission may have a different perspective, but the Administrative Law Judge is not persuaded,

⁴²⁶ Ex. 38 (Zins Rebuttal) at 25-26.

⁴²⁷ Ex. 112 (Pollock Direct) at 38-42; Ex. 113 (Pollock Rebuttal) at 13-14; Tr. 4:14, 37.

⁴²⁸ Ex. 38 (Zins Rebuttal) at 26.

⁴²⁹ Ex. 63 (Schedin Rebuttal) at 5.

⁴³⁰ Ex. 38 (Zins Rebuttal) at 26-27.

⁴³¹ *Id.*

⁴³² *Id.* at 3.

based on the arguments in the record, that the costs of Grand Meadow should be treated differently than other generation sources in Xcel's CCOSS. The Administrative Law Judge accordingly recommends that the Commission adopt Xcel's classification of costs and allocate 4.5% of the cost of Grand Meadow to capacity and 95.5% to energy in the CCOSS.

C. Class Revenue Apportionment

266. The issue of how to allocate the revenue responsibility between the various classes (as distinguished from cost responsibility discussed above) has two subparts: how to perform the initial allocation, based on Xcel's proposed revenue requirement; and how to adjust that allocation to reflect the final revenue requirement, as determined by the Commission.

267. Xcel proposed a revenue allocation to the various classes based on a combination of cost and rate stability factors. Its initial proposal was to allocate revenue responsibility as follows: Residential, 35.5%; C&I Non-Demand, 6.3%; C&I Demand, 59.1%; and Lighting, 1%. Xcel's proposal is summarized below.⁴³³

Customer Class	Current Revenue (000)	Cost (000)	Xcel Proposed Revenue (000)	Total Revenue (%)	Revenue Increase (%)	Over/Under Cost (%)
Residential	\$ 902.7	\$ 998.3	\$ 971.8	35.5%	7.6%	(2.7%)
C&I Non-Demand	\$ 113.6	\$ 113.6	\$ 120.7	4.4%	6.3%	5.9%
C&I Demand	\$ 1,537.8	\$ 1,599.1	\$ 1,616.5	59.1%	5.1%	1.1%
Lighting	\$ 26.0	\$ 24.7	\$ 26.7	1.0%	2.8%	7.5%
Total	\$ 2,580.1	\$ 2,735.7	\$ 2,735.7	100.0%	6.0%	

268. Under Xcel's proposal, the increase in the revenue apportionment to the residential class is above average—7.6%, compared to the average of 6.0%. This differential indicates that Xcel is attempting to move the revenue apportionment for the residential class closer to cost. At the same time, Xcel avoids concerns about rate shock by increasing the revenue apportionment gradually rather than all at once, which would result in an increase of about 10.4% for the residential class.⁴³⁴

269. If this apportionment method is applied to Xcel's alternative proposed deficiency of \$119 million (assuming its Nuclear Stability Plan with a

⁴³³ Ex. 80 (Peirce Direct) at 5 & SLP-2; Ex. 40A (Huso Direct) at 5.

⁴³⁴ Ex. 80 (Peirce Direct) at 7.

three-year life extension is adopted), the revenue increases are reduced to 6.9%, Residential; 3.4%, C&I Non-Demand; 3.5%, C&I Demand; and -0.4%, Lighting.⁴³⁵

270. If this apportionment method is used and applied to the revenue deficiency calculated by the OES (\$91.7 million, without inclusion of Grand Meadow in base rates), it would result in an increase of 5.1% to the Residential class; 3.8% to C&I Non-Demand; 2.7% to C&I Demand; and 0.4% to Lighting.⁴³⁶

271. If the final revenue requirement approved by the Commission is lower than the one proposed by Xcel, it will be necessary to adjust the proposed revenue allocation to reflect the final revenue requirement. In this event, Xcel proposes a method of moving closer to cost by reducing class cost differences in proportion to a reduced revenue deficiency. The proposed residential class responsibility, for example, is 35.52%, or 36.49% of total cost. This ratio (35.52/36.49) is 0.97%. If the Commission were to approve a revenue increase that is 25% less than proposed by Xcel, the Residential class responsibility would be increased by a factor of 25% times 0.97%, or 35.76%.⁴³⁷ The other class responsibilities would be C&I Non-Demand, 4.35%; C&I Demand, 58.94%; and Lighting, 0.96%.⁴³⁸ Xcel points out that the proposed Residential rate using this method is below cost by only 0.74% of retail revenues.⁴³⁹ The XLI disputes this characterization, maintaining that a rate increase measured on total revenues will mask the degree to which rates would move toward cost.⁴⁴⁰

272. If Xcel's alternative apportionment were applied to the revenue deficiency calculated by the OES, it would result in an increase in revenue responsibility of 6.3 percent to the Residential class.⁴⁴¹

273. The OES recommends that the Commission adopt Xcel's initially proposed revenue apportionment. The OES also recommends using these same percentages in the event the Commission approves a reduced revenue requirement, with no further adjustment made toward cost.⁴⁴²

274. XLI proposed moving all classes except the Residential and Lighting classes 50% closer to cost, as determined by its CCOS.⁴⁴³

275. MCC also proposed allocating revenue responsibility to customer classes based strictly on the results of the CCOS approved by the Commission; in other words, it advocated that no non-cost factors should be considered. It contends this rate design is appropriate to minimize impacts on businesses,

⁴³⁵ Xcel Initial Brief at 74.

⁴³⁶ Ex. 81 (Peirce Surrebuttal) at 2 & SLP-S-1.

⁴³⁷ See Ex. 41 (Huso Rebuttal) at 4. The equation is $35.52\% + (25\% \times 0.97\%) = 35.76\%$.

⁴³⁸ Xcel Initial Brief at 75.

⁴³⁹ Xcel Initial Brief at 75.

⁴⁴⁰ Ex. 114 (Pollock Surrebuttal) at 28.

⁴⁴¹ Ex. 81 (Peirce Surrebuttal) at 2.

⁴⁴² Ex. 80 (Peirce Direct) at 5.

⁴⁴³ Ex. 112 (Pollock Direct) at 49 & Schedules 13-14.

school districts, and governments. If individual residential customers are unable to pay their bills at the cost level determined by the CCOSS, the MCC proposes providing a subsidy only by expanding the Low Income Energy Discount Rider, reducing the fixed monthly charge, or making other changes necessary to help individual low income customers. It also maintains this approach would send appropriate price signals to support conservation.⁴⁴⁴

276. The Commercial Group advocates apportioning revenue responsibility strictly in accordance with Xcel's CCOSS.⁴⁴⁵ Assuming a revenue deficiency of \$119 million, it would advocate increases of 9.1% for the Residential class; -1.3% for C&I Non-Demand; 2.6% for C&I Demand; and -6.2% for Lighting.

277. Based on its argument that any CCOSS performed would be arbitrary and should not be used to determine class revenue responsibility, the OAG proposes a uniform or across-the-board increase for all customer classes.⁴⁴⁶ For example, if the total revenue requirement is increased by 4.6%, each customer class would be increased by that percentage.

278. The proposals by the XLI, the MCC, and the Commercial Group to allocate revenue responsibility based largely or solely on cost would result in rate shock for the Residential class. The OAG's proposal to apply an increase uniformly across classes disregards the relative cost responsibilities of each class.

279. Xcel's initially proposed allocation of the revenue requirement represents a significant movement toward cost, while minimizing rate shock. The Administrative Law recommends that the Commission adopt Xcel's apportionment of the revenue requirement to customer classes as follows: Residential, 35.5%; C&I Non-Demand, 6.3%; C&I Demand, 59.1%; and Lighting, 1%. The Administrative Law Judge also recommends using these same percentages to allocate a lower revenue requirement to customer classes. Given current economic conditions, there should be no further movement toward cost for the residential class at this time.

D. Customer Charge

280. Xcel proposed an increase in the Residential customer charge from \$6.00 to \$6.50. The OES agreed.⁴⁴⁷ In its Initial Filing, Xcel recommended a \$2.00 increase to the C&I Demand customer charge, raising it to \$24.00.⁴⁴⁸ The OES recommended that the C&I Demand customer charge be increased to

⁴⁴⁴ Ex. 61 (Schedin Direct) at 14-15; Tr. 3:19.

⁴⁴⁵ Ex. 50 (Baudino Direct) at 8.

⁴⁴⁶ Ex. 66 (Lindell Direct) at JLL-1.

⁴⁴⁷ Ex. 80 (Peirce Direct) at 8.

⁴⁴⁸ Ex. 40 (Huso Direct) at (SVH-1), Schedule 4.

\$25.00 per month.⁴⁴⁹ Xcel agreed that this is reasonable.⁴⁵⁰ Xcel further recommended increasing the present \$25.00 customer charge to \$28.00 for the comparable C&I time-of-day customer charge.⁴⁵¹ No party commented on or objected to this recommendation. The parties consider this matter resolved, and the Administrative Law Judge agrees that this resolution is in the public interest.

E. C&I Demand and Energy Charges

281. C&I Demand and energy charges assume that service is provided at secondary voltage. Demand charges are billed relative to a customer's maximum metered (kW) demand in the billing month, while the base rate energy charges are billed on the kWh purchased. Both demand and energy charges are time-differentiated for loads at or above 1,000 kW. The lower costs of serving loads delivered at higher voltages (primary, transmission transformed, and transmission) are reflected in Xcel's demand and energy voltage discounts.⁴⁵²

282. Based on its arguments regarding the CCROSS, the XLI contends that Xcel's demand and energy charges do not appropriately reflect capacity and energy costs. It maintains the Xcel had under-priced the demand charge and over-priced the energy charge. It argues that Xcel should recover the increase to this class through higher demand charges and should not increase the energy charges in the C&I Demand rates.⁴⁵³

283. The Administrative Law Judge has concluded that the CCROSS appropriately treats capacity and energy costs. Accordingly, the Administrative Law Judge recommends that Xcel's proposed C&I Demand rates be approved.

F. Interruptible Rates

284. Xcel proposed to retain the existing amount of the interruptible rate discount (which has the effect of decreasing the percentage of the discount compared to firm rates). XLI and MCC objected, maintaining that a larger discount should be available for interruptible customers. The MCC also requested a market study of the existing terms and conditions under which it offers interruptible service.⁴⁵⁴

285. Xcel agreed with the proposal to perform a market study.⁴⁵⁵ The purpose of the study would be to reassess the interruptible rates programs and find opportunities to optimize the relationships between different interruptible options and discounts, and the relationship between interruptible service and

⁴⁴⁹ Ex. 80 (Peirce Direct) at 8-9.

⁴⁵⁰ Ex. 41 (Huso Rebuttal) at 5.

⁴⁵¹ *Id.*

⁴⁵² Ex. 112 (Pollock) at 50-51.

⁴⁵³ *Id.* at 50-52; Ex. 115 at 4.

⁴⁵⁴ Ex. 61 (Schedin Direct) at 22.

⁴⁵⁵ Ex. 41 (Huso Rebuttal) at 12-13.

other sources of peaking capacity.⁴⁵⁶ Xcel has provided an outline of the study that it intends to conduct, and it has agreed to meet with parties and establish a reasonable timeline for completion following the final Order in this proceeding.⁴⁵⁷ In addition, Xcel agreed to alter the terms and conditions under which Tier 1 Peak Short Notice Rider service is provided.⁴⁵⁸ The MCC and Xcel consider this issue resolved for the purposes of this proceeding.⁴⁵⁹ The XLI accepted these changes, but the settlements do not resolve the interruptible service issues raised by the XLI.⁴⁶⁰

286. XLI maintains that there should be no increase in Peak Control Demand charges and that Interruptible credits should be increased to reflect between 49% and 65% of the avoided capacity cost of a new combustion turbine.

287. The Tier 1 Peak controlled Short Notice Rider continues to require annual certification of interruptible load. The XLI maintains that annual certifications are burdensome and should be waived for those customers that have successfully complied with interruptions during previous peak periods.⁴⁶¹

288. As noted above, Xcel views interruptible service as a form of purchased peaking service, for which it should not pay more than the market requires. It maintains the discount should balance the cost to other ratepayers (who must absorb the foregone revenues) against the value of the discount to Interruptible customers, who take this service based on an economic decision that compares the costs of being interrupted against the cost savings provided by the discount.

289. Xcel contends use of an avoided cost method would produce an excessive discount and is analytically inappropriate, because Interruptible customers have not purchased a combustion turbine and are not entitled to any measure of return incorporated into an avoided cost. In addition, Interruptible customers receive a discount even when there is no interruption. As long as Xcel has purchased adequate capacity, it argues there is no justification to effectively purchase more by increasing the Interruptible discount.

290. In response to the XLI's concern about the certification process, Xcel modified the proposed Short Notice Rider certification requirements to require a one-hour interruption as opposed to a four-hour interruption each year.⁴⁶² It maintains that because customers must make system changes within ten minutes of receiving notice of an interruption, the annual testing and

⁴⁵⁶ *Id.*

⁴⁵⁷ Ex. 56 (Huso Supplemental Hearing Statement) at 2 and Schedule 1; Tr. 2B:8-9.

⁴⁵⁸ Ex. 53 (Zins Supplemental).

⁴⁵⁹ Tr. 3:21 (Schedin). The Administrative Law Judge believes the Performance Factor issue initially raised by the MCC has been resolved in this agreement and will be addressed in the study of Interruptible rates.

⁴⁶⁰ Tr. 2A:30.

⁴⁶¹ Ex. 112 (Pollock Direct) at 61.

⁴⁶² Ex. 53 (Zins Supplemental Hearing Statement) at 2-3 & Schedule 3.

certification process is necessary to demonstrate that these customers can perform when called upon. Moreover, Xcel points out that there have been no recent peak control periods and that Schedule L and Short Notice customers have not been interrupted since 2001, so the proposal to waive certification based upon compliance during “previous peak periods” would be difficult to implement.

291. The Administrative Law Judge concludes that Xcel has established that its Interruptible rate and discount are appropriate and should be approved.

G. Rate Design of Riders

292. The XLI and MCC request that the same rate design principles used to allocate costs between capacity and energy when designing rates in a general rate case also be used to design rates for rate riders. In addition, the XLI and MCC argue that where base rate costs have been allocated to customer classes on a demand basis, the riders should have an explicit demand charge for C&I Demand customers.⁴⁶³

293. Xcel opposes this request, contending that the Commission should continue its use of a simplified process for rider rates on the basis that administrative ease, combined with the need for a speedy, non-controversial method for recovering costs over a comparatively short period of time, justify this approach. It maintains that any deviation from cost causation is temporary because the costs recovered in riders are eventually rolled into base rates.⁴⁶⁴

294. With regard to the RES Rider, Xcel argues for continued recovery through an energy charge on the basis that it would be administratively difficult to develop special demand and energy rates for rider recovery of renewable resources. It envisions that a “mini-rate case” would result each time the company seeks to add projects such as wind-to-battery, solar, and biomass energy, as customer classes would compete to shift costs to other classes. For wind energy in particular, Xcel maintains that the amount properly allocated to demand is so small as not to have a material effect.

295. With regard to the TCR Rider, Xcel assigns all costs to classes based on demand; however, it uses an energy charge to recover those costs. Xcel again argues that the complexity of attempting to develop a demand/energy rate design for this single cost is not justified.

296. The OES agrees with Xcel that a more streamlined approach should be used to set rates for riders.⁴⁶⁵

⁴⁶³ Ex. 112 (Pollock Direct) at 65-66; Ex. 114 (Pollock Surrebuttal) at 25; Ex. 115 at 5; Ex. 61 (Schedin Direct) at 9.

⁴⁶⁴ Tr. 2A:75-76 (Zins).

⁴⁶⁵ Ex. 81 (Peirce Surrebuttal) at 4.

297. Riders are intended to provide for cost recovery between rate cases for projects that are deemed to be in the public interest. It does not appear that there will be long periods of time between rate cases in the coming years. The Administrative Law Judge recommends that Xcel's existing rider recovery mechanism be approved. In the future, given the expected investments in the CapX 2020 project, it may be appropriate to require Xcel to propose an alternate demand-based charge for the TCR Rider.

H. Fuel Clause Rider

1. Updates to FCR Tariff

298. Xcel updated the base cost of energy that appears on Sheet 91 of the Fuel Clause Rider (FCR) tariff.⁴⁶⁶ The OES agreed with the method used in calculating the base cost of energy, but recommended that Xcel include a new base cost of energy in its final compliance filing,⁴⁶⁷ consistent with previous Commission orders.⁴⁶⁸ Xcel agreed to include a new base cost of energy in the final compliance filing.⁴⁶⁹

299. Xcel also updated the Class Cost ratios, the Time-of-Day ratios, the Fuel Adjustment Factor ratios, and the class-specific base cost of energy. Xcel used the method approved in the last rate case. OES reviewed these calculations and found them to be correct. The amounts may require revision depending on the Commission's decisions in this case.⁴⁷⁰

300. Xcel uses the E8760 allocator to allocate fuel costs to the various customer classes. The resulting class fuel ratios are used each month to allocate changes in fuel costs until the next rate case. The allocator assumes that all C&I Demand customers will pay the same fuel charges.

301. The XLI contends that fuel costs should be further allocated based on delivery voltage within the C&I class (Secondary, Primary, Transmission Transformed, or Transmission delivery). It argues that Xcel's proposed FCR would overcharge customers taking service at the Primary, Transmission Transformed, and Transmission levels.⁴⁷¹

302. In response, Xcel maintains that differences in line losses are calculated for all energy costs (including fuel) and are applied through the non-fuel discount provided to Primary, Transmission Transformed, and Transmission services. If line losses were credited to the FCA instead of through those

⁴⁶⁶ Ex. 36 (Zins Direct) at 11.

⁴⁶⁷ Ex. 77 (Ouanes Direct) at 2-3.

⁴⁶⁸ *In the Matter of the Petition of Northern States Power Company d/b/a Xcel Energy for Approval of a New Base cost of Energy*, Docket No. E002/MR-08-1316, Order Setting New Base Cost of Energy at 2 (Dec. 23, 2008).

⁴⁶⁹ Ex. 41 (Huso Rebuttal) at 6.

⁴⁷⁰ Ex. 77 (Ouanes Direct) at 4.

⁴⁷¹ Ex. 112 (Pollock Direct) at 67-68.

discounted rates, the FCR would be significantly more complex and the energy rate discount would need to be recalculated. It contends there would be no net change in the overall discount.⁴⁷²

303. Xcel also increased the Time-of-Day (TOD) on-peak/off-peak ratio from 1.67 to 1.89, based on the E8760 allocator. The MCC believes that this increase is not justified, because the cost of natural gas is currently lower than when the marginal cost study used to develop the allocator was conducted.

304. In response, Xcel argues that natural gas prices are expected to increase during the time period when these rates will be in effect. In addition, it maintains it accounted for this change by moderating the increase in the non-fuel rate ratio, using a 1.70 TOD ratio for base rates. This resulted in a weighted overall TOD ratio of 1.79 for the combination of base energy rates and fuel cost charges.⁴⁷³

305. The Administrative Law Judge recommends that the Commission approve Xcel's proposed updates to the Fuel Clause Rider.

2. MISO Day 2 Language

306. The OES objected to Xcel's proposed language in the Fuel Clause Rider, provision 3, related to recovery of MISO Day 2 expenses, and recommended a simplified version of the provision.⁴⁷⁴ In response, Xcel proposed a revised version of the provision, similar to the OES recommended version.⁴⁷⁵ The OES and Xcel agreed that this revised version will not affect Xcel's current MISO expense recovery authorized by the Commission, but rather, will merely serve to minimize the need for future language modifications as energy markets in the MISO footprint continue to evolve.⁴⁷⁶ The agreed upon language is as follows:

All Midwest ISO (MISO) costs and revenues authorized to flow through the Fuel Clause Charge by the Commission, subject to the applicable terms of the Commission Orders, and excluding MISO costs and revenues that are recoverable in base rates.

3. FCA Cap and Incentive System

307. The OAG recommended that the Commission impose a 3% price cap on Xcel's FCA.⁴⁷⁷ The MCC recommended that the Commission order Xcel to report regularly on FCA forecast accuracy and to implement a top-level

⁴⁷² Ex. 38 (Zins Rebuttal) at 28-29.

⁴⁷³ Ex. 41 (Huso Rebuttal) at 14.

⁴⁷⁴ Ex. 77 (Ouanes Direct) at 4; Ex. 79 (Ouanes Surrebuttal) at 2.

⁴⁷⁵ Ex. 53 (Zins Supplemental Hearing Statement) at 5.

⁴⁷⁶ *Id.*

⁴⁷⁷ Ex. 66 (Lindell Direct) at 10.

incentive system related to FCA forecast accuracy.⁴⁷⁸ Xcel generally supported the concept of FCA incentives.⁴⁷⁹ But it maintained that an incentive mechanism should be considered outside the rate case and that Xcel should not be treated differently than other electric utilities in Minnesota.⁴⁸⁰

308. Xcel held settlement discussions with the OAG, MCC, and OES (the parties who submitted pre-filed testimony on the issue of FCA incentives).⁴⁸¹ The parties agreed to a settlement of the issue for the purposes of this proceeding. The parties agreed:

Parties to this proceeding have asserted the need for improved incentives for the Company to minimize fuel and purchased power costs, where possible. The Office of the Attorney General (OAG) has proposed a 3% cap on fuel and purchased power costs. The other parties agree that a well designed incentive system could mitigate these costs.

This issue should be addressed through a cooperative effort by stakeholders, including all electric utilities. The Commission's investigation into the FCA (Docket No. E999/CI-03-802) provides an appropriate forum for this joint effort.

The OAG agrees to withdraw its proposal for a 3% cap on fuel and purchased power costs from consideration in this rate case proceeding provided that: The Company commits to providing an FCA incentive proposal to the workgroup formed through Docket No. E999/CI-03-802 for consideration by stakeholders and for potential implementation by electric utilities. The work group would review and modify the proposed mechanism, as needed. Such proposal will include a provision that provides positive and negative financial consequences for the Company. The Company agrees that it will not argue that the filed rate doctrine or federal preemption prevents the implementation of such an FCA incentive mechanism.

The Company will provide the proposal to the workgroup no later than 90 days following the Commission's Order in this proceeding.⁴⁸²

I. Hiawatha Line Energy Charge Credit

309. Xcel proposed to reduce the Energy Charge Credit (ECC) provided to the Hiawatha Light Rail Line (HLRL) customer. The ECC is a demand-metered rate component that applies a credit to higher load factor sales. The credit recognizes the lower cost of providing qualifying ECC sales, which are the

⁴⁷⁸ Ex. 61 (Schedin Direct) at 5-6.

⁴⁷⁹ Ex. 49 (Beuning Supplemental Hearing Statement) at 4.

⁴⁸⁰ *Id.*

⁴⁸¹ *Id.*

⁴⁸² *Id.* at Schedule 1 (Proposed FCA Incentive Settlement); Tr. 3:86-88.

monthly kWh sales in excess of the product of multiplying monthly non-coincident peak kW demand by 400 hours of use.⁴⁸³ Xcel determined that the current formula was providing too generous a discount because the use of coincident peak procedures produced too many qualifying hours, against which the credit was applied, which in turn produced a larger credit than would result for other customers with conventional non-coincident demands.⁴⁸⁴ It elected to use instead the credit provided to Real-Time Pricing (RTP) customers, because their typical contract demand levels are also less than conventional non-coincident – peak billed peak demand.⁴⁸⁵ This change would reduce the credit from 0.9 cents per kWh to 0.77 cents per kWh.⁴⁸⁶ This amounts to a 0.2% increase in the bill.⁴⁸⁷

310. The OES agrees with the ECC reduction proposed by Xcel.⁴⁸⁸

311. The MCC objects to reducing the ECC for this customer. The MCC argues that the coincident-peak billed demand for the HLRL is the same as the non-coincident peak billed demand for a single customer location that has totalized metering. Therefore, the MCC contends the HLRL is not unique in qualifying for the higher amount of credit. The MCC also maintains that, because the Light Rail Tariff was cooperatively developed to capture all the benefits of the diversity within the light rail system, it should not be revised because Xcel now considers it to over-compensate for that diversity.⁴⁸⁹

312. The ECC is intended to be based on non-coincident peak demand; under the LRT Tariff, however, the ECC is calculated using coincident peak demand, which is significantly lower than its non-coincident peak demand. This overestimates the ECC at the expense of other customers.⁴⁹⁰ The Administrative Law Judge accordingly recommends that the Commission approve the ECC reduction to the HLRL as proposed by Xcel.

J. CIAC True-Up

313. Under Xcel's existing tariff, Secondary or Primary Voltage level customers are responsible for any costs resulting from service installations or extensions that exceed three and one-half times the customer's anticipated revenue. Customer payments toward installation or extension costs are referred to as contribution in aid of construction (CIAC) and are non-refundable.⁴⁹¹

⁴⁸³ Ex. 42 (Huso Surrebuttal) at 2.

⁴⁸⁴ *Id.*

⁴⁸⁵ *Id.*

⁴⁸⁶ Ex. 63 (Schedin Rebuttal) at 2-3.

⁴⁸⁷ Ex. 42 (Huso Surrebuttal) at

⁴⁸⁸ Ex. 80 (Peirce Direct) at 18.

⁴⁸⁹ (Ex. 63 (Schedin Rebuttal) at 3.

⁴⁹⁰ Ex. 81 (Peirce Surrebuttal) at 8-9.

⁴⁹¹ NSP-M Tariff Sheets 6-22, 6-23, 6-26.

314. The MCC proposes that a true-up mechanism be established to reconcile actual revenues during the three and one-half years following the installation or extension with the estimated revenues used to determine the CIAC. Under the MCC proposal, Xcel would refund any “excess” CIAC payment. Xcel would not, however, be permitted to charge a customer more if it has determined that the CIAC payment was not adequate.⁴⁹²

315. Xcel points out that the purpose of requiring a CIAC is to protect existing customers from having to pay unreasonably higher rates as a result of higher-cost additions being placed into rate base.⁴⁹³ A mechanism that “trues up” only for the benefit of the new customer is not reasonable. In addition, Xcel argues that the proposal would be administratively difficult and labor intensive, and other customers should not have to pay for these costs.

316. The Administrative Law Judge concludes that Xcel has established that the current CIAC framework is reasonable and the changes advocated by MCC should not be adopted.

K. Service Quality Tariff Revision

317. Under Xcel’s Quality of Service Plan (QSP), individual customers in all classes receive a \$50 credit for unexcused power outages when service is interrupted more than six times in a twelve-month period or if an interruption lasts for 24 hours or more.⁴⁹⁴

318. The SRA contends the credit to municipal customers for any unexcused outage, regardless of duration, should be increased to \$200. The SRA maintains this is more representative of the direct costs that municipalities incur in the event of unexcused outages. When power goes out, municipalities often use mobile gas generators that are moved to affected lift stations to prevent sewers from backing up or to water production facilities. The minimum charge for an on-call operator is \$100 for a two-hour minimum. Actual costs are frequently much higher, depending on the length of the outage.⁴⁹⁵

319. Xcel maintains that the outage credit in the QSP is not intended to compensate customers for costs associated with an outage, but is intended to function as a service quality incentive. It characterizes the SRA’s proposal to establish a Municipal Pumping credit of \$200 for unexcused outages as compensation for costs or damages resulting from an outage, and it recommends that the SRA participate in the QSP Docket, which is due for re-evaluation later

⁴⁹² Ex. 61 (Schedin Direct) at 35; Tr. 3:29-32 (Schedin).

⁴⁹³ Xcel Initial Brief at 99.

⁴⁹⁴ NSP-M Tariff Sheet 6-7.10.

⁴⁹⁵ Ex. 59 (Cote Direct) at 1-5.

this year. Xcel suggests that service quality issues such as outage credits would be better addressed in a forum that includes other electric utilities.⁴⁹⁶

320. The SRA points out that the tariff language provides that a credit is made for the purpose of compensating customers, and the credits are referred to as “penalties.”⁴⁹⁷

321. The SRA’s proposal is not a request for compensatory damages. It has provided evidence that the credit amounts in the QSP are set too low for municipal customers to provide an appropriate service quality incentive. The Administrative Law Judge can see no reason why it would be more appropriate to address this issue in a proceeding in which other utilities participate. The Administrative Law Judge accordingly recommends that the Commission adopt the SRA’s proposal to modify the QSP tariff to establish a \$200 credit for municipal pumping customers for each unexcused outage, regardless of duration.

L. Resolved Rate Design Issues

1. Calendar Month Meter Reading and Billing

322. The MCC recommended that Xcel be ordered to modify its General Rules and Regulations to allow a C&I customer the option to select calendar month billing.⁴⁹⁸ The MCC and Xcel agreed that additional study of this issue is warranted.⁴⁹⁹ Xcel committed to completing a study of this issue within 180 days of the Commission’s Order in this proceeding.⁵⁰⁰ Xcel also committed to working with the MCC after completion of the study toward a cost-effective and reasonable implementation of the proposal.⁵⁰¹ The study would include an analysis of the most cost-effective way to implement this potential service offering, as well as any barriers or additional costs associated with its implementation.⁵⁰² The MCC and Xcel consider this issue resolved.

2. Cancellation of Flint Hills Tariff

323. In January 2007, Flint Hills Resources, which had previously received only distribution and transmission services from Xcel pursuant to a contract tariff, resumed taking full electric service under standard full service tariffs.⁵⁰³ Because of this change, the special contract tariff applicable only to

⁴⁹⁶ Ex. 41 (Huso Rebuttal) at 21-22.

⁴⁹⁷ Tariff 1.9E6; 1.9F; SRA Reply Brief at 6.

⁴⁹⁸ Ex. 61 (Schedin Direct) at 32-33.

⁴⁹⁹ Ex. 53 (Zins Supplemental Hearing Statement) at 1-2.

⁵⁰⁰ *Id.* at 2.

⁵⁰¹ *Id.*

⁵⁰² *Id.*

⁵⁰³ Ex. 36 (Zins Direct) at 24.

Flint Hills was no longer needed, and Xcel proposed to cancel the tariff.⁵⁰⁴ The OES agreed.⁵⁰⁵

3. Coincident Peak (Demand Aggregation)

324. The MCC also recommended that Xcel be ordered to modify its General Rules and Regulations to allow demand-metered customers the option to select coincident peak billing (or aggregate billing), to extend the Hiawatha Light Rail Tariff to additional light rail systems, and to provide the metering equipment required to use this billing method.⁵⁰⁶ Xcel objected to these recommendations based on its position that aggregate billing is only appropriate where the customer has a load requirement that is large enough and unique enough so that the generation capacity-related cost of their service can be clearly shown to be fundamentally different from the class to which they belong.⁵⁰⁷ Only one such customer exists in Minnesota, which is the Hiawatha Light Rail customer.⁵⁰⁸ On surrebuttal, the MCC modified its recommendations to extend the Hiawatha Light Rail Tariff to all similarly situated customers and to allow aggregate billing for meters that serve contiguous parcels under the control of one authority.⁵⁰⁹

325. The parties met to discuss the issue and agreed on a proposed modification to the language of the General Rules and Regulations in the form of Demand Aggregation Criteria.⁵¹⁰ The terms require that demand aggregation accounts be under the same customer and authority, that the customer's load and cost-of-service must be clearly shown by empirical data to be sufficiently large and different from others in its class, and for the customer to pay for the metering equipment if the customer fails to make such a showing.⁵¹¹ Based on this agreement, the MCC and Xcel consider this issue resolved.⁵¹²

4. Distributed Wind Generation Tariff Language

326. The MCC cited language from the "Availability" provision of the Small Distributed Wind Generation Purchase Tariff, in Section 10 of the Rate Book, which it felt could be interpreted to mean that in order to qualify for the distributed generation (DG) wind tariff (and perhaps other similar DG tariffs), the customer must be the owner of the generator.⁵¹³ Xcel does not believe that the customer must own the generator located on the customer premise to qualify

⁵⁰⁴ *Id.* Ex. 40A (Huso Direct) at SVH-1 Schedule 9, p. 5.

⁵⁰⁵ Ex. 80 (Peirce Direct) at 30.

⁵⁰⁶ Ex. 61 (Schedin Direct) at 32.

⁵⁰⁷ Ex. 38 (Zins Rebuttal) at 39.

⁵⁰⁸ *Id.* at 38.

⁵⁰⁹ Ex. 64 (Schedin Surrebuttal) at 16.

⁵¹⁰ Ex. 65, Demand Aggregation Criteria.

⁵¹¹ *Id.*

⁵¹² Tr. 3:12 (Schedin).

⁵¹³ Ex. 61 (Schedin Direct) at 34.

under the Small Distributed Wind Generation Purchase Tariff. Xcel amended Tariff Sheet No. 1, Section No. 10 to clarify this issue.⁵¹⁴

5. Elimination of Trouble Hourly Charge

327. Xcel proposed to eliminate hourly charges for trouble calls and charges for meter testing.⁵¹⁵ It also recommended charging customers, on a time and materials basis, for calls stemming from problems originating in the customer's facilities.⁵¹⁶ The OES recommended adoption of these proposals.⁵¹⁷

6. Interval Load Data Service

328. The MCC further recommended that Xcel be required to add to its General Rules and Regulations a description of and related charges for the interval meter and load data service that it offers to large C&I customers.⁵¹⁸ The interval meter and load data service provides customers with the capability of measuring and storing load requirements on a minute-by-minute (continuous interval) basis.⁵¹⁹ Some customers find this information useful for their internal energy planning purposes.⁵²⁰ Xcel agreed to add the requested description to its General Rules and Regulations, and MCC has agreed to Xcel's proposed language.⁵²¹ The MCC and Xcel consider the issue resolved.

7. Low Income Energy Discount Rider

329. To address the needs of its low-income customers, Xcel proposed increasing the Low Income Energy Discount Rider by 100 kWhs, to the first 400 kWhs of use by qualifying customers.⁵²² The OES recommended approval of this proposal.⁵²³

8. Meter Reading

330. The MCC proposed that customers be given the opportunity of establishing monthly calendar-based meter read dates for ease of budgeting and other efficiencies. Xcel and MCC agreed that additional study of this issue is warranted. Xcel committed to perform a study that would include an analysis of the most cost-effective way to implement this potential service offering, as well as any barriers or additional cost associated with its implementation. Xcel committed to completing this study within 180 days of the Commission's Order in

⁵¹⁴ Ex. 53 (Zins Supplemental Hearing Statement) at 3; and (PJZ-4) Schedule 4.

⁵¹⁵ Ex. 40B (Huso Direct) at Schedule 10 Sections 6.6 and 6.13.

⁵¹⁶ *Id.*

⁵¹⁷ Ex. 80 (Peirce Direct) at 32.

⁵¹⁸ Ex. 61 (Schedin Direct) at 33.

⁵¹⁹ Ex. 38 (Zins Rebuttal) at 41.

⁵²⁰ *Id.*

⁵²¹ Ex. 53 (Zins Supplemental Hearing Statement) at Schedule 2.

⁵²² Ex. 6 (Sparby Direct) at 5; Ex 40A (Huso Direct) at 13.

⁵²³ Ex. 80 (Peirce Direct) at 15.

this proceeding and to working with the MCC following conclusion of the study toward cost-effective and reasonable implementation of this project.⁵²⁴

9. Miscellaneous Text Changes in Tariff

331. In its Initial Filing, Xcel proposed a number of miscellaneous text changes to Section 6 of its tariff,⁵²⁵ section 1.4 (Continuity of Service), section 3.7 (Bill Date Due) and section 4.1 (Use of Service).⁵²⁶ It also proposed to include standard contract language for an Underground Gas and/or Electric Distribution Agreement,⁵²⁷ which is currently in its natural gas tariff book and was recently approved by the Commission.⁵²⁸ The OES recommended adoption of the changes with one correction, namely that the statutory reference in Section 4.1, Use of Service, should be Minn. Stat. §326B.106, subd. 12, rather than Minn. Stat. §16B.61, subd. 8.⁵²⁹ Xcel concurred with this correction.⁵³⁰

10. Retail Wheeling/Remote Renewable Generation

332. The MCC recommended that the Commission order Xcel to design retail wheeling rates⁵³¹ and to submit a tariff implementing the rates.⁵³² This issue was investigated through a multi-party workgroup overseen by the OES in response to the same request by the MCC in Xcel's last general electric rate case (Docket No. E002/GR-05-1428).⁵³³ The outgrowth of that investigation was a rate that the MCC did not find acceptable.⁵³⁴ The current status of the issue is that the University of Minnesota is slated to make a new proposal, but has not done so.⁵³⁵ Xcel agreed to continue discussions with the University of Minnesota after the current proceeding.⁵³⁶ The MCC and Xcel now consider this issue resolved for the purposes of this proceeding.

11. Rider Forecasts

333. The MCC recommended that Xcel be ordered to provide a 24-month quarterly updated forecast of each rider to its C&I demand-metered customers.⁵³⁷ It also recommended that the updates have the same quarterly

⁵²⁴ Ex. 53 (Zins Supplemental Hearing Statement) at 1-2; Tr. 2A at 72.

⁵²⁵ Ex. 80 (Peirce Direct) at 32.

⁵²⁶ Ex. 40A (Huso Direct) at (SVH-1), Schedule 10.

⁵²⁷ Ex. 80 (Peirce Direct) at 32.

⁵²⁸ *In the Matter of the Application of Northern States Power Company for Authority to Increase Rates for Natural Gas Service in Minnesota*, Docket No. G002/GR-06-1429, Findings of Fact, Conclusions of Law and Order (Sept. 10, 2007).

⁵²⁹ Ex. 80 (Peirce Direct) at 33.

⁵³⁰ Ex. 41 (Huso Rebuttal) at 5.

⁵³¹ Ex. 61 (Schedin Direct) at 25.

⁵³² Ex. 64 (Schedin Surrebuttal) at 16.

⁵³³ Ex. 61 (Schedin Direct) at 24 and LLS-19.

⁵³⁴ Ex. 53 (Zins Supplemental Hearing Statement) at 5.

⁵³⁵ *Id.* at 5-6.

⁵³⁶ Tr. 2A: 73 (Zins).

⁵³⁷ Ex. 61 (Schedin Direct) at 8.

intervals and update policies as the FCR.⁵³⁸ Xcel proposed adding a provision to each rider tariff that will provide 24-month forecasts to customers who sign a protective agreement.⁵³⁹ The forecasts for each rider will be updated annually on October 1st, with the forecast for the FCR updated quarterly.⁵⁴⁰ The affected riders are: FCR, EIR/MERP, TCR, RDF, RES, SEP and CIP.⁵⁴¹

12. Seasonal Service

334. Xcel proposed a reconnection charge for customers who disconnect their service for a seasonal absence and then request that service be reconnected at that same address during the same year.⁵⁴² The OES agreed that this was a reasonable charge, but was concerned about customer notification of the reconnection charge.⁵⁴³ Xcel provided testimony that that it has in place the necessary protocols for customers to be informed of this reconnection charge.⁵⁴⁴ At hearing, the OES recommended approval of Xcel's proposed reconnection charge.⁵⁴⁵

13. State Energy Policy (SEP) Rider

335. Xcel had proposed rolling the State Energy Policy (SEP) Rider revenue requirement into base rates. The OES opposed that proposal, primarily because some of the costs currently recovered through the SEP Rider are expected to terminate in 2012 and 2013. If those costs continue to be recovered through the Rider, the rate would be reduced when the costs terminate, whereas if the costs were included in base rates, the rate would not be reduced until the next rate case. Xcel accepted the OES proposal to continue the SEP Rider, which also eliminates the OES concern about double recovery of the SEP costs during the interim rate period through the Rider and recovery again in final rates.⁵⁴⁶

14. Standby and Supplemental Service

336. The MCC recommended that the transmission component of the Standby and Supplemental Service (S&S) tariffs should be the unbundled network service cost included in standard retail rates, rather than the MISO Open Access Transmission Tariff (OATT) rate proposed by Xcel.⁵⁴⁷ Xcel did not object

⁵³⁸ *Id.*

⁵³⁹ Ex. 45 (Heuer Supplemental) at 5 and Schedule 3.

⁵⁴⁰ *Id.*

⁵⁴¹ *Id.* at Schedule 3.

⁵⁴² Ex. 36 (Zins Direct) at 17-18.

⁵⁴³ Ex. 80 (Peirce Direct) at 30-31.

⁵⁴⁴ Ex. 53 (Zins Supplemental Hearing Statement) at 4.

⁵⁴⁵ Tr. 3:130 (Peirce).

⁵⁴⁶ Ex. 15 (Heuer Rebuttal) at 41; Ex. 81 (Peirce Surrebuttal) at 4.

⁵⁴⁷ Ex. 64 (Schedin Surrebuttal) at 8.

to revising its S&S tariffs to replace the OATT rate with the test-year 2009 Minnesota jurisdiction transmission cost component.⁵⁴⁸

15. Street Lighting Issues

337. The SRA challenged the portion of the Xcel's tariff⁵⁴⁹ that required a billing credit for daily energy charges if a street lamp repair is not completed within 72 hours after the Company receives notice of the outage.⁵⁵⁰ After the evidentiary hearings, Xcel and the SRA met to discuss how best to resolve this dispute. They agreed that this matter could best be explored in a separate docket.⁵⁵¹ In the interim period, Xcel's existing street lighting tariff would remain unchanged.⁵⁵²

338. The SRA withdrew all its street lighting issues and is no longer pursuing them in this proceeding.⁵⁵³ The issues expected to be explored in the separate docket would include the following as well as other issues identified in the process:

Whether street lighting services should be only tarified, or whether there are benefits to Xcel Energy or customers having both a filed tariff and individual contracts;

What type of standard or credit should apply to outages and restorations;

Whether long-term maintenance contracts should be required and whether an exit fee or other arrangement should be allowed; and

How should customers be informed about energy efficiency and new lighting options and technology developments.⁵⁵⁴

16. Transmission Cost Rider

339. The OES recommended that Xcel provide a compliance filing demonstrating that no double-recovery of costs occurs during the test year period. Xcel has agreed to provide such a compliance filing.⁵⁵⁵

17. Voltage Service Quality

340. The MCC recommended that Xcel be required to create a new service quality measure to address power voltage quality.⁵⁵⁶ Xcel and the MCC

⁵⁴⁸ Ex. 53 (Zins Supplemental Hearing Statement) at 6.

⁵⁴⁹ NSP-M Tariff Sheet at 5-83; see also Ex. 41 (Huso Rebuttal) at 18.

⁵⁵⁰ Ex. 57 (Clancy Direct) at 1; Ex. 58 (Clancy Surrebuttal) at 1-2.

⁵⁵¹ Xcel Initial Brief at 101; SRA Initial Brief at 2.

⁵⁵² Xcel Initial Brief at 101.

⁵⁵³ SRA Initial Brief at 2.

⁵⁵⁴ Xcel Initial Brief at 101.

⁵⁵⁵ Ex. 80 (Peirce Direct) at 22-23; Ex. 16 (Heuer Direct) at 44.

agreed that the issue of power voltage quality would be better addressed in a separate generic proceeding that includes all electric utilities.⁵⁵⁷ The purpose of the proceeding would be to consider whether there is a need for new quality standards or incentives on an industry-wide basis.⁵⁵⁸ Xcel committed to requesting that the Commission establish such a proceeding and to advancing the proceeding in a timely manner.⁵⁵⁹ The MCC and Xcel consider this issue resolved for the purposes of this proceeding.

Based on these Findings of Fact, the Administrative Law Judge makes the following:

CONCLUSIONS

1. The Minnesota Public Utilities commission and the Administrative Law Judge have jurisdiction over the subject matter of this proceeding pursuant to Minn. Stat. Chapter 216B and Minn. Stat. § 14.50.

2. Every rate made, demanded, or received by any public utility shall be just and reasonable. Rates shall not be unreasonably preferential, unreasonably prejudicial or discriminatory, but shall be sufficient, equitable and consistent in application to a class of consumers. To the maximum reasonable extent, the Commission shall set rates to encourage energy conservation and renewable energy use and to further the goals of sections 216B.164, 216B.241, and 216C.05. Any doubt as to reasonableness should be resolved in favor of the consumer.⁵⁶⁰

3. The burden of proof to show that a rate change is just and reasonable shall be upon the public utility seeking the change.⁵⁶¹

4. If an applicant and all intervening parties agree to a stipulated settlement of the case or parts of the case, the settlement must be submitted to the Commission. The Commission shall accept or reject the settlement in its entirety. The Commission may accept the settlement on finding that to do so is in the public interest and is supported by substantial evidence.⁵⁶²

5. In the event the Commission rejects the agreements of the parties, this matter may be extended by 60 days for conclusion of the contested case proceedings under the terms of Minn. Stat. § 216B.16, subs. 1a and 2.

⁵⁵⁶ Ex. 61 (Schedin Direct) at 31.

⁵⁵⁷ Ex. 53 (Zins Supplemental Hearing Statement) at 1; Tr. 2A:72.

⁵⁵⁸ *Id.*

⁵⁵⁹ *Id.*

⁵⁶⁰ Minn. Stat. § 216B.03.

⁵⁶¹ Minn. Stat. § 216B.16, subd. 4.

⁵⁶² Minn. Stat. § 216B.16, subd. 1a(b).

6. The record supports the resolution of the settled, resolved, and uncontested matters identified above. These matters have been resolved in the public interest and are supported by substantial evidence.

7. Rates set in accordance with the terms of this Report would be just and reasonable. Specifically, the record supports resolution of the contested issues in the following manner:

Reject Xcel's proposed Nuclear Stability Plan and instead require Xcel to modify its depreciation expense for Prairie Island by assuming the remaining life will be extended by ten years;

Require that decommissioning and end-of-life fuel expenses for Prairie Island be calculated by assuming the remaining life will be extended by ten years;

Approve the use of Xcel's General Allocator (39.74%) in allocating unassigned costs;

Decrease test year expense by \$727,917 to reflect that inadequate expenses were allocated to municipal customers;

Move Grand Meadow project costs into rate base; allocate approximately \$2.7 million in Production Tax Credits to base rates, with the remainder to be flowed through the RES Rider, with an annual true-up;

Accept Xcel's proposed nuclear fuel outage costs for the test year;

Accept Xcel's proposed rate case expense and amortization schedule;

Set the return on equity at 10.88%, and the rate of return at 8.83%;

Adopt Xcel's Class Cost of Service Study;

Use the stratification method to classify Grand Meadow project costs in the CCOS;

Apportion the revenue requirement to customer classes in the following manner: Residential, 35.5%; C&I Non-Demand, 6.3%; C&I Demand, 59.1%; and Lighting, 1%;

Approve Xcel's proposed C&I Demand and Energy charges;

Approve Xcel's proposed Interruptible rates and discounts;

Maintain Xcel's existing mechanism for recovery of rates in riders;

Approve Xcel's proposed changes to the Fuel Clause Rider;

Approve Xcel's proposal to reduce the Energy Charge Credit for the Hiawatha Light Rail Line;

Maintain the existing process for the CIAC; and

Revise Xcel's Quality Service Plan to add a \$200 credit for municipal pumping customers for each unexcused outage, regardless of duration.

Based upon these Conclusions, the Administrative Law Judge makes the following:

RECOMMENDATION

The Administrative Law Judge recommends that the Commission issue an Order providing that:

1. Xcel is entitled to increase gross annual revenues in accordance with the terms of this Report.

2. Within ten days of the service date of this Report, Xcel shall file with the Commission for its review and approval, and serve on all parties in this proceedings, revised schedules of rates and charges reflecting the revenue requirements for 2009 and the rate design decisions based on the recommendations contained herein.

3. If the Commission orders an Interim Rate Refund within 30 days of the service date of this Order, Xcel shall file with the commission for its review and approval, and serve upon all parties to this proceeding, a proposed plan for refunding to all customers, with interest, the revenue collected during the Interim Rate period in excess of the amount authorized herein.

4. Xcel shall make further compliance filings regarding rates and charges, rate design decisions, and tariff language as ordered by the Commission.

Dated: August 24, 2009

/s/ Kathleen D. Sheehy

KATHLEEN D. SHEEHY

Administrative Law Judge

Reported: Transcript Prepared (five volumes)
Shaddix & Associates

NOTICE

Notice is hereby given that, pursuant to Minn. Stat. § 14.61, and the Rules of Practice of the Public Utilities Commission and the Office of Administrative Hearings, any party adversely affected by this Report may file exceptions to it within 15 days of the mailing date hereof. Exceptions should be filed with the Executive Secretary, Minnesota Public Utilities Commission, 350 Metro Square, 121 Seventh Place East, St. Paul, MN 55101. Exceptions must be specific and stated and numbered separately. Proposed Findings of Fact, Conclusions and Order should be included, and copies thereof shall be served upon all parties. If desired, a reply to exceptions may be filed and served within ten days after the service of the exceptions to which reply is made. Oral argument before a majority of the Commission will be permitted to all parties adversely affected by the Administrative Law Judge's recommendation who request such argument. Such request must accompany the filed exceptions or reply. An original and 15 copies of each document should be filed with the Commission.

The Minnesota Public Utilities Commission will make the final determination of the matter after the expiration of the period for filing exceptions or after oral argument, if held. Further notice is hereby given that the Commission may, at its own discretion, accept or reject the Administrative Law Judge's recommendation and that the recommendation has no legal effect unless expressly adopted by the Commission as its final order.

Under Minn. Stat. § 216B.16, subd. 1a, if the Commission rejects or modifies the settlement agreements reached herein, this matter may be extended by 60 days for conclusion of the proceeding.

Under Minn. Stat. § 14.63, subd. 1, the Commission is required to serve its final decision upon each party and the Administrative Law Judge by first class mail or as otherwise provided by law.